**Commonwealth of Kentucky**
**Division for Air Quality**

# *RESPONSE TO COMMENTS*

ON THE TITLE V DRAFT PERMIT V-06-007
**EAST KENTUCKY POWER COOPERATIVE, INC.**
Hugh L. Spurlock Generating Station
MAYSVILLE, KY
JUNE 1, 2006
COMBUSTION SECTION, REVIEWER
SOURCE I.D. #: 21-161-00009
SOURCE A.I. #: 3004
ACTIVITY ID #: APE20040001

## SOURCE DESCRIPTION:

An application for renewal of Title V Permit V-97-050 Revision II for the East Kentucky Power Cooperative Inc.-Hugh L. Spurlock Generating Station was received on June 8, 2004. The permit renewal is combined with renewals of the Phase II Acid Rain and $NO_x$ Budget permits, and is combined with a major modification for the construction of boiler Unit 04 (Emission point 17).

East Kentucky Power Cooperative (EKPC) submitted an air permit application dated September 13, 2004 seeking a permit to construct a new 300 megawatt (MW) net nominal generating unit (Emission Unit 17) at its existing Spurlock Generating Station located at Maysville in Mason County, Kentucky. In response to comments from the Division for Air Quality (DAQ), the National Park Service (NPS), and the U. S. EPA, additional information was received from EKPC on December 22, 2004, May 12, 2005, May 26, 2005, August 24, 2005, October 27, 2005, November 9, 2005, November 16, 2005, December 8, 2005, December 21, 2005, January 13, 2006, and January 20 2006. The application was considered to be administratively complete upon receipt of the revised modeling information on January 20, 2006.

The new unit will utilize circulating fluidized bed (CFB) technology. The new CFB boiler will be equipped with Selective Non Catalytic Reduction (SNCR), Pulse Jet Fabric Filters (PJFF), Dry Scrubbing (DS), and Limestone Injection pollution control systems.

Existing equipment at the Spurlock Generating Station includes two (2) Pulverized Coal boilers and one Circulating Fluidized Bed boiler. Emission Unit 01 is a 3500mmBtu/hr dry-bottom wall-fired boiler equipped with an electrostatic precipitator and low-$NO_x$ burner, for which construction began before 1971. The precipitators were installed as a part of the original plant construction but were rebuilt in 1990-1992. In addition, a selective catalytic reduction device was installed in 2003.

Emission unit 02 is a 4850 mmBtu/hr tangentially fired boiler equipped with electrostatic precipitators, low-$NO_x$ burners, and a flue gas desulfurization (FGD) system and was subject to review under 40 CFR 52.21 (PSD) in November, 1979. The FGD system is not currently operating, and has not operated since 1985. A selective catalytic reduction device has been installed since the original Title V permit issuance.

U.S. EPA has brought an action in U.S. District court concerning EPA's allegation of past NSR violations on emission unit 02. A trial is currently scheduled in the near future. Upon resolution of the issues raised, the Division may be required to reopen this permit.

Emission unit 08 is a 2500 mmBtu/hr CFB boiler equipped with a baghouse filter, flash dry absorber (FDA), and a selective non-catalytic reduction (SNCR) unit.

The 144 mmBtu/hr auxiliary boiler (Emission Unit 03) is no longer in operation and has been permanently removed from the site. There is a natural draft cooling tower, coal/limestone/ash material handling equipment, an emergency liquefied petroleum gas generator, and fuel oil storage tanks. The existing natural draft cooling tower, coal/limestone/ash material handling equipment, and fuel oil storage tanks will increase utilization when the new CFB boiler becomes operational.

The new facilities that will be constructed as part of this renewal project will include the CFB boiler (Emission Unit 17) and its associated control equipment. Additional material handling units to be constructed include coal piles, coal silos, a fly ash bed, fly ash silo, and a limestone silo. The existing combustion units (Emission Units 01, 02 and 08) are not part of the proposed major modification, and have previously gone through Prevention of Significant Deterioration (PSD) review.

The proposed project constitutes a major modification of a major stationary source as defined in 401 KAR 51:017, Prevention of Significant Deterioration of Air Quality. The proposed project will result in a significant net emissions increase, as defined in 401 KAR 51:001 Section 1(146), of the following regulated air pollutants: Particulate matter (PM & $PM_{10}$), carbon monoxide (CO), volatile organic compounds (VOC), fluorides, nitrogen oxides (NOx), sulfur dioxide ($SO_2$), and sulfuric acid ($H_2SO_4$) mist. The project will not emit lead above the significant emission rate for lead of 0.6 tons per year (tpy), set forth in 401 KAR 51:001 Section 1(221) and 40 CFR 51. Project emissions of hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds will also be below significant emission levels and are therefore not subject to PSD review.

**PUBLIC AND U.S. EPA REVIEW:**

An advertisement was placed in the Maysville Ledger Independent on February 16, 2006 announcing the public comment period. A second advertisement was placed in the Marysville Ledger Independent on February 24, 2006, announcing a public hearing. The Division for Air Quality received comments on the draft permit during the public hearing in Maysville, Kentucky on March 30, 2006.

Comments were received from the U.S. EPA, Region 4, Clean Air Task Force, Sierra Club, and East Kentucky Power Cooperative. Attachment A to this document lists the comments received and the Division’s response to each comment. Minor changes were made to the permit as a result of the comments received, however, in no case were any emissions standards, or any monitoring, recordkeeping or reporting requirements relaxed. Please see Attachment A for a detailed explanation of the changes made to the permit. The U.S. EPA has 45 days to comment on this proposed permit.

The following abbreviations/acronyms are used in these comments in addition to commonly understood abbreviations/acronyms such as lb for pound and hr for hour:

BACT - best available control technology
CEM - continuous emissions monitor
CEMS – continuous emissions monitoring system

CFB - circulating fluidized bed
EAB – EPA Environmental Appeals Board
EKP - East Kentucky Power Cooperative
EPA - U.S. Environmental Protection Agency
ESP – electrostatic precipitator
KDAQ - Kentucky Division for Air Quality
mmBtu -million British thermal units
MWh - megawatt-hour (of gross energy output)
NSPS - new source performance standards (in 40 CFR part 60)
PC - pulverized coal
PSD - prevention of significant deterioration
SCR - selective catalytic reduction
SNCR - selective non-catalytic reduction
TDF - tire-derived fuel

# ATTACHMENT A

## Response to Comments

**Comments submitted by the Clean Air Task Force (CATF):**

We urge the Division of Air Quality to deny the Spurlock permit. The failure to include IGCC in the BACT analysis is contrary to federal law. By Kentucky's own permit application files, IGCC emerges as BACT when compared to CFB and PC in a recent air permit application. There is no reason to believe that a similar analysis at Spurlock would reach any different conclusion.

**Division's Response:**

*IGCC would result in a redefinition of the basic design of the project and is not required under a BACT analysis. While the Division has asked for a review of IGCC technology in recent permits, it is the Division's understanding of the BACT review process that a fundamental redefinition of the project to an IGCC process is not required.*

*In addition, Stephen D. Page, Director, Office of Air Quality Planning and Standards, recently addressed this issue in his letter of December 13, 2005. Director Page determined that U.S. EPA "would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit." While the Division is aware that this determination of U.S. EPA is being challenged, we find that letter is consistent with the Division's understanding of the Act and regulations.*

*In addition, the Page determination state that review of IGCC could be performed under Section 165(a)(2) of the Clean Air Act that states:*

*(2) the proposed permit has been subject to a review in accordance with this section, the required analysis has been conducted in accordance with regulations promulgated by the Administrator, and a public hearing has been held with opportunity for interested persons including representatives of the Administrator to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations;*

*The Division has considered CATF's comments as suggesting an IGCC system as an alternative to the construction of a CFB. With consideration of the staged nature of the construction at Spurlock and available information on IGCC technology, the Division will not require the use of an IGCC design as an alternative to a CFB.*

## Comments submitted by EPA Region IV, March 15, 2006 "Comments on Draft PSD/Title V Operating Permit for East Kentucky Power Cooperative, Hugh L. Spurlock Generating Station, E.A. Gilbert Unit 4 Project"

### A. EKP Supplemental BACT Analysis

1. Comparison of Unit 4 to Unit 3 - EKP states the following on page 3 with reference to Unit 4: "The boiler will be a 300 MW Circulating Fluidized Bed (CFB) boiler identical to Unit 3." [Emphasis added.] At a later point in the analysis, EKP describes the heat input for Unit 4 as 2,800 MMBtu/hr. We understood the rated capacity values for Unit 3 to be a heat input of 2,500 MMBtu/hr and a gross energy output of 270 MW. These values indicate that Unit 4 is not "identical" to Unit 3, but rather is slightly larger. The difference in size between the two units, if any, may not be of importance for an evaluation of Unit 4, but we ask for clarification of energy input and output characteristics.

**Division's Response:**

*EKPC has advised that the units are from the same manufacturer and are the same model number. Apparently, Unit #3 was one of the first units of that model produced, and the manufacturer estimated equipment ratings very conservatively until they had accumulated more operating experience in a commercial environment.*

2. Emissions Data from Unit 3 - On pages 2 and 3 (Section 1.1.1), EKP enumerates the reference sources from which comparison data were obtained. Neither here nor anywhere else in the analysis does EKP acknowledge that operating data for the "identical" Spurlock Unit 3 are available and could serve as direct, site-specific comparison data. We understand, however, that you probably had access to Unit 3 data when making your BACT determination. The extent to which you used Unit 3 data in reaching your conclusions should be described in detail. (See related comment below.) If EKP believes that Unit 3 monitoring data are not relevant for some reason, EKP should explain the lack of relevance.

***Division's Response:***

*The Division partially concurs. A single performance test cannot substitute for a long-term performance guarantee. The Division did consider the performance test results of unit 3 during its review of BACT and gave the performance results appropriate consideration in setting Unit #4's BACT limits.*

3. Tire-derived Fuel - We understand that EKP is requesting approval to burn some amount of tire-derived fuel (TDF) along with the primary coal fuel. The supplemental analysis contains no mention of TDF or any assessment of whether combustion of TDF could affect the BACT evaluation. Consideration of TDF combustion should be considered explicitly before you arrive at a final BACT determination.

**Division's Response:**

*The Division concurs that the use of TDF should be identified more explicitly in the permit, so changes have been made to mirror the language used for Unit 3. The use of TDF results in similar and in some cases, slightly lower, emissions than EKPC's design coal, so an explicit BACT analysis was not deemed necessary.*

4. BACT Assessment for Sulfur Dioxide

a. Page 8 contains a table showing that purchased washed coal can achieve about 10 percent less $SO_2$ emissions compared to EKP design coal at a cost effectiveness value of only $423/ton removed. Assuming this value is accurate, used of washed coal should be considered reasonable from an economic standpoint as a BACT option for $SO_2$. In addition, the cost effectiveness of low-sulfur eastern bituminous coal ($3,092/ton removed) is marginally within the range of costs that have been considered acceptable for $SO_2$ control. According to the data in the page 8 table, low-sulfur eastern bituminous coal would produce $SO_2$ emissions that are about 85 percent less than those from EKP design coal.

b. On page 7 EKP compares the delivered cost per ton of various coal types. The stated cost of low-sulfur western Powder River Basin (PRB) coal ($52.50/ton) is twice as high as the "EKP design coal" ($26.97). Since some coal-fired steam generating units in the Eastern U.S. burn PRB coal, we request that you verify this substantial price difference. Just a cursory search on our part produced information showing recent spot prices of PRB coal running far below the spot prices of many other coals. However, these spot prices may not account for transportation and Btu-differential costs. Please note also that EKP included a discussion (on page 5) about "legislative history" to the effect that a BACT assessment should not "give a competitive advantage to those states with cheaper low sulfur coal." We do not know why EKP made this point if PRB coal is so much more expensive than EKP design coal.

c. On page 9, EKP states that "Coal washing would do little to achieve the overall control of emissions that is required and can only be achieved with modern high-efficiency add-on control devices." We do not understand the point being made here. Use of washed coal would not be an alternative to the use of an add-on control device, but rather would result in lower $SO_2$ emissions when combined with an add-on device.

**Division's Response:**

*The Division does not concur that a limit restricting the coal sulfur content is appropriate or necessary for this type of unit, nor is the Division aware of any other permits for this type of facility that contain a limit in the permit on the percentage of sulfur that the fuel can contain. Further, coal washing is not uniformly effective in reducing sulfur on eastern coal. According to publicly available information at http://www.coaleducation.org, the sulfur content of Eastern Kentucky coal is not significantly reduced by coal washing.*

5. <u>BACT Assessment for Nitrogen Oxides</u> - EKP assesses SCR as a $NO_x$ control alternative and concludes that an emissions rate achievable with SNCR should be selected as BACT rather than an emissions rate based on use of SCR. Although we have not reached a different opinion, we request that you take note of the following comments before making a final BACT determination for $NO_x$ emissions:

   a. On page 11 EKP states that "the presence of alkaline particulate matter emitted from a CFB boiler would preclude effective SCR operation due to catalyst poisoning." This statement would be strengthened by verification from an SCR catalyst vendor. SCR system catalysts have performed well for long periods of time when exposed to high particulate matter loadings in PC boiler applications despite the fact that such particulate matter can be alkaline to some degree.

**Division's Response:**

*At the time of this permit, based on information available, Kentucky still concludes that use of SCR is technically infeasible for use with a high ash CFB. Kentucky notes that there is very limited application of SCR on biomass CFB units, but Kentucky is unaware of any technical demonstration of SCR on a coal units. Until such time, Kentucky concurs that an SCR is technically infeasible.*

   b. As the controlled level of $NO_x$ emissions for the option CFB + SCR, EKP used an emissions rate of 0.067 lb/MMBtu on the assumption "that SCR applied on a CFB boiler can control $NO_x$ to the same level of emissions as for a PC boiler." PC boilers can achieve a lower emissions rate than 0.067 lb/MMBtu. For example, the permit recently issued for the proposed new Louisville Gas & Electric Trimble County PC boiler is based on an emissions rate of 0.05 lb/MMBtu.

**Division's Response:**

*See Response above.*

   c. In its cost analysis for SCR (Attachment 1, no page number), EKP included a capital recovery factor (referred to as "Total Annualized Installed Costs") of approximately $14,000,000. In addition, EKP included a "Depreciation" cost of approximately $12,000,000 based on 30 percent of purchased cost. In our opinion, including a depreciation cost in addition to a capital recovery cost is double counting. The depreciation cost should not be allowed. Further, the capital recovery cost is based on an interest rate of 10 percent which is higher than the recommended value of 7 percent in *EPA Air Pollution Control Cost Manual* (Sixth Edition, January 2002). An interest rate higher than 7 percent requires justification.

**Division's Response:**

*Response: EKP redid the SCR cost analysis to address EPA's concerns. EKP contends that an SCR would have an average cost of $14,273 per ton of $NO_x$ removed assuming an emission rate of 0.05 lb/mmBtu (from Trimble). This cost is for an SCR located after the baghouse and includes the cost of reheating the flue gas with natural gas. However, it should be noted that Kentucky did not eliminate the SCR on a cost basis, as the Division has made the determination than an SCR is technically infeasible (see above response to subpart a., this same comment).*

d. EKP discusses the collateral environmental impacts of SCR on page 14. Although such a discussion is appropriate, it is also appropriate to remember that SCR systems are in widespread use on coal-fired boilers and that the collateral impacts from SCR use are manageable.

**Division's Response:**

*The Division acknowledges the comment.*

6. Particulate Matter CEMS - EKP provides a rationale on page 24 to justify not having a PM CEMS as a compliance demonstration method for filterable particles. We do not agree with EKP's conclusion and we support your decision to require a PM CEMS for demonstration of compliance with the filterable emissions limit. Use of a PM CEMS is especially suited to installations such as the Unit 4 project where a wet flue gas desulfurization method will not be employed. If needed, we can supply additional information to support a requirement for use of a PM CEMS.

**Division's Response:**

*The Division acknowledges the comment.*

7. BACT Assessment for Sulfuric Acid Mist - In its assessment of sulfuric acid mist control methods (page 32), EKP lists three control methods not including a wet ESP. Associated with this list is footnote 16 (page 32) in which this statement appears: "It is EKP's technical judgment that a wet ESP is not necessary for a CFB with a dry scrubber." Strictly speaking, making a "technical judgment" does not mean that a wet ESP is technically infeasible. A wet ESP should have been included in the list of feasible control methods. We are in agreement, however, that the combination of CFB with limestone injection plus a dry scrubber is an acceptable sulfuric acid mist control method.

**Division's Response:**:

*The Division concurs with the conclusion that BACT for sulfuric acid mist for this unit is a CFB with limestone injection plus a dry scrubber.*

8. Miscellaneous - This sentence appears on page 9: "$NO_2$ is converted to NO in the air once emitted." Although atmospheric photochemical reactions involving oxides of nitrogen are complicated, the general first assumption is that NO converts to $NO_2$. We are simply pointing this out. EKP's comment has no direct relevance to the BACT assessment.

**Division's Response:**

*EPA is correct and the statement should have read: "NO is converted to $NO_2$ in the air once emitted." This statement is in the application, and is not contribute to any conclusions in the permit.*

## B. KDAQ Statement of Basis and Draft Permit

1. Additional Unit 4 Enforceable Limits - The final permit for Unit 4 should contain enforceable limits for heat input (2,800 MMBtu/hr) and gross energy output (300 MWh) or enforceable limits in terms of pounds per hour as well as enforceable limits in terms of pounds per MMBtu and pounds per MWh. A limit solely in terms of pounds per MMBtu or pounds per MWh does not establish an upper limit on hourly emissions unless accompanied by a limit on heat input and gross energy output. We do not view a listing of heat input and energy output in the "Description" section of the permit as enforceable.

**Division's Response:**

*The Division does not concur that there is a regulatory requirement to set enforceable limits on heat input. However, the Division has included emission limits consistent with the compliance periods in the modeling analysis. The Division does concur that information listed in the description of each emission point are not enforceable limits.*

2. Unit 4 Allowable Fuels - The final permit should describe the allowable types of solid fuel(s) to be burned in Unit 4. We further recommend that the final permit include an enforceable condition on the types of solid fuels and the allowable percentages of different solid fuel types. For example, one condition in the draft permit (the condition with an emissions limit for mercury) indicates that tire derived fuel (TDF) may be burned. Another condition contains a statement that the "permittee shall monitor and record the TDF tonnage and 10% tire to coal ratio for fuel usage on a monthly basis." This monitoring provision suggests that the permit contains an enforceable restriction on TDF use, but we did not find one. We recommend including an enforceable limit on the maximum quantity of TDF that can be burned, either on a heat input basis or total fuel weight basis. Simply listing a 10-percent TDF ratio in the "Description" section of the permit for Unit 4 as is done for Unit 3 would not constitute an enforceable limit.

**Division's Response:**

*The facility will burn no more than 10% tire derived fuel (TDF) as a weight percentage of total fuel burned. This has been included in the permit as an enforceable operating limit for both Unit 3 and Unit 4 (emission units 8 and 17).*

3. Accounting for Comparable Emissions from Unit 3 - In the case of an emissions unit that is being added at a facility where a virtually identical and operational unit already exists, appropriate BACT comparison points are the emissions levels that the existing unit has achieved in the past. We believe that KDAQ may have taken into account actual emissions from Unit 3 in arriving at BACT emissions limits for Unit 4. If this is the case, the statement

of basis would benefit from a summary of Unit 3 actual emissions. If actual emissions from Unit 3 have been lower than any of the BACT emissions limits proposed for Unit 4, an explanation is needed as to why emissions rates achieved in practice at Unit 3 cannot be achieved by Unit 4.

**Division's Response:**

*The Division did consider operating results and performance test results from Unit 3 in the determination of appropriate BACT emission limits. However, at the time the permit was being drafted only a single performance test had been run and Unit 3 had been operating for only a short period of time. Consequently, the Division also gave consideration to manufacturers' guarantees, operating results at other similar CFBs, and the difference between short-term operating results and long-term operational capability.*

4. Unit 4 Nitrogen Oxides Emissions Limits - Consistent with our previous comments on this project, we continue to believe that a single emissions limit should be established as best available control technology (BACT) for $NO_x$ emissions without the allowance of an optimization study that could result in a higher limit at a future time. However, we acknowledge that the proposed limits are consistent with our previous comments in that the BACT target limit is 0.07 lb/MMBtu (30-day average), and that the optimization study can result in an emissions limit no higher than 0.09 lb/MMBtu.

**Division's Response:**

*The Division acknowledges the comment.*

5. Unit 4 Particulate Matter Emissions Limits - We have the following comments:

   a. Condition B.2.a) for Unit 4 contains an emissions limit for "particulate matter" and for "total particulates." You should make clear that these limits encompass $PM_{10}$ emissions since $PM_{10}$ is a regulated NSR pollutant subject to PSD review for this project.

**Division's Response:**

*The Division concurs, and condition B.2.a) for Unit 4 has been clarified in the permit.*

   b. Related to the Unit 4 emissions limit in Condition B.2.a) for "total particulates," we presume that this limit includes condensables. You should state specifically that the limit for total particulates covers condensable as well as filterable particles. Consistent with this recommendation, an appropriate monitoring method for condensables should be specified (see next comment).

**Division's Response:**

*See response to comment 5.c. (below).*

c. Condition B.4.b) for Unit 4 contains the following statement: "... to meet the compliance assurance monitoring requirement for particulate matter, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 3-hour or 30 day average value exceeds that standard ...." Since the only 3-hour limit in Condition B.2.a) is for "total particulates," presumably including condensibles, use of a CEM might not be appropriate. A method appropriate for condensibles should be specified as the compliance method for the 3-hour limit. Related to this subject, Condition D.4. provides that a CEM shall be used to demonstrate continuing compliance with the emission standards for $PM/PM_{10}$. Monitoring of condensibles should be addressed in this condition as well.

**Division's Response:**

*See Section D, which specifies that applicable reference methods or equivalent test methods specified in the permit and approved by the Cabinet and US EPA are to be used for all regulated pollutants including* $PM/PM_{10}$.

6. Unit 4 Carbon Monoxide Emissions Limits - The compliance averaging period for the CO emissions limit is 30 days. This 30-day compliance averaging period is not consistent with the 1-hour and 8-hour averaging periods for the CO national ambient air quality standards, the 1-hour and 8-hour averaging periods for the PSD significant impact levels, or the 8-hour averaging period for the CO *de minimis* impact level that can be used to support an ambient monitoring exemption.

**Division's Response:**

*Response: The Division has revised the permit to include an 8-hour basis of 420 lb/hour excluding periods of startup, shutdown and malfunctions. This value is consistent with the emission rate modeled.*

7. NSPS References and Emissions Limits for Unit 4 - We have the following comments:

a. Some of the draft emissions limits for Unit 4 contain the phrase "per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005." The NSPS revisions have now been finalized. The phrase should read "per final revisions to NSPS subpart Da effective February 27, 2006" or something like this.

**Division's Response:**

*The Division concurs, and the phrase has been deleted.*

b. Condition B.2.e) for Unit 4 contains an $SO_2$ limit of 2.0 lb/MWh (gross energy output) on a 3-hour average basis taken from the proposed NSPS subpart Da revisions of February 2005. This limit should be revised to reflect the final NSPS revisions effective February 27, 2006. The final standard is 1.4 lb/MWh (gross energy output) on a 30-day rolling average basis. (Incidentally, the proposed revision was on a 30-day rolling average basis, not on a 3-hour basis.)

**Division's Response:**

*The Division concurs, and the change has been made*

c. The regulation citation in Condition B.2.j) for Unit 4 should be 40 CFR 60.45Da instead of 40 CFR 60.45a. EPA changed the numbering format for subpart Da in a final rule correction issued on August 30, 2005.

*Division's Response:*

*The Division concurs, and the change has been made.*

8. Unit 4 Startup and Shutdown Permit Conditions – We are still reviewing the provisions of the permit related to startup, shutdown, and malfunction, and will submit any comments during review of the proposed title V permit.

**Division's Response:**

*The Division acknowledges the comment.*

9. Kentucky Ambient Standards for Fluorides - Kentucky has a set of ambient air quality standards for gaseous fluorides and total fluorides (401 KAR 53:010). Neither the permit application nor the statement of basis contains an assessment of compliance with ambient standards for fluorides.

**Division's Response:**

*Response: EKP did perform the required modeling for fluoride emissions. As indicated in the separate responses provided to Stan Krivo's modeling comments, the modeling indicated that emissions from EKP will not cause or contribute to an exceedance of the fluoride standards. This has been added to the statement of basis for the purposes of clarity and completeness.*

10. Impacts on Nearby Nonattainment Areas - The Spurlock Station site is close to the greater Cincinnati 8-hour ozone nonattainment area and $PM_{2.5}$ nonattainment area. It is also close to another $PM_{2.5}$ nonattainment area in Ohio. KDAQ did not acknowledge the existence of these nonattainment areas in the ambient analysis section of the statement of basis. Further, you did not provide either a quantitative or qualitative assessment of whether emissions from the Spurlock Unit 4 are likely to interfere with attainment of ambient ozone and $PM_{2.5}$ standards in these nonattainment areas. We recommend that you at least acknowledge the existence of these areas and provide an opinion as to why approval of the Unit 4 project will not adversely contribute to ambient concentrations in excess of ambient air quality standards. (Please see Item 2 in our comment memo dated October 4, 2005, for a suggestion on this subject.) We also remind you of the provisions in 401 KAR 51:052 for sources located in designated attainment areas that could cause or contribute to a violation of a national ambient air quality standard.

**Division's Response:**

*EPA requested that EKP provided a qualitative or quantitative assessment of whether emissions from Spurlock Unit 4 are likely to interfere with attainment of the fine particulate matter ($PM_{2.5}$) ambient standards in the greater Cincinnati $PM_{2.5}$ nonattainment area or in a separate $PM_{2.5}$ nonattainment area in Ohio.*[1] *(See EPA's request in their March 15, 2006 Comments (at 7).) Because EPA has not yet promulgated $PM_{2.5}$ implementation rules officially establishing the pollutants affecting $PM_{2.5}$ ambient air quality concentrations, EPA has recommended (in interim guidance dated April 5, 2005) that direct $PM_{10}$ emissions be used as a surrogate to address the NSR requirements for the $PM_{2.5}$ ambient standards. In response to the EPA comment, and using the approach suggested by EPA guidance, EKP reviewed its previous Unit 4 modeling results for $PM_{10}$ and assessed whether concentrations attributable to Unit 4 would exceed the $PM_{10}$ significant impact levels at the nearest $PM_{2.5}$ nonattainment areas.*

*As explained in the Air Quality Analysis of EKP's September 13, 2004, PSD permit application for Spurlock Unit 4, a detailed analysis was done to determine whether Unit 4's emissions of $PM_{10}$ would have a significant impact at any point beyond the boundaries of the plant site.*[2] *That analysis showed that the greatest distance from the plant at which Unit 4 $PM_{10}$ emissions will have a significant air quality impact is 2 km. In other words, the detailed modeling analysis submitted by EKP as part of its PSD permit application for Spurlock Unit 4 demonstrates that at all points more than 2 km from that Unit -- and the EPA-specified PM nonattainment areas are both more than 2 km from the Spurlock plant site -- particulate emissions from Unit 4 will not have a significant impact on ambient particulate matter concentrations. See Section 4.3 of the Air Quality Analysis in the PSD Permit Application for Spurlock Unit 4.*

*The Division accepts this analysis as showing that EKP has satisfied the requirement to demonstrate that Spurlock Unit 4's projected emissions of particulate matter will not contribute significantly to any violation of a particulate matter ambient standard in a downwind PM2.5 nonattainment area.*

11. Miscellaneous - We have the following miscellaneous comments:

    a. In Condition B.4.e) for Unit 4, the term "nitrogen oxide" should be "nitrogen oxides."

**Division's Response:**
**Division's Response:**

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[1] EKP VOC emissions (Unit 4 and Unit 3 combined) are less than 100 tons per year. Therefore, an ambient impact analysis is not required for ozone per 401 KAR 51:017, Section 7(5). Additionally, emissions from Unit 4 are not significant as they are less than 40 tons per year at 24.53 tons per year.

[2] EKP's modeling analysis also considered whether other emissions from Unit 4 would have significant off-property impacts. As summarized in Table 4-2 of that analysis, an initial screening analysis showed that $SO_2$ and $PM_{10}$ were the only pollutants for which significant off-property impacts were predicted to occur; thus, more refined modeling was done to analyze whether those impacts would adversely impact compliance with any applicable ambient air quality standards or PSD increments. The initial screening analysis showed that maximum impacts of $NO_x$ and CO for all averaging periods were below the significant impact levels for all modeled years of meteorological data and, therefore, would not have the potential to cause or contribute to any increment ($NO_x$ only) or ambient standard violation.

*The Division concurs and the change has been made.*

b. Condition D.7. contains the phrase "as detailed in Condition 2." We believe this phrase should be "as detailed in Condition D.6."

**Division's Response:**

*The Division concurs and the change has been made.*

c. Condition K.3) contains the phrase "two (2) 2500 mmBtu/hr pulverized coal-fired CFB boilers." This phrase should be "one 2500 mmBtu/hr coal-fired CFB boiler and one 2800 mmBtu/hr coal-fired CFB boiler" (with commas added before and within this phrase as appropriate).

**Division's Response:**

*The Division concurs and the change has been made.*

d. In the statement of basis you refer to the Hugh L. Spurlock Power Station. According to the permit application, the actual official name is the Hugh L. Spurlock Generating Station.

**Division's Response:**

*The Division concurs and the change has been made.*

**Comments submitted by East Kentucky Power Cooperative (EKPC)**

Emissions Unit 01 - Indirect Heat Exchanger (Unit 1)
The exceptions to the emission limit expressed for opacity is inconsistent with the cited regulation. The cited regulation provides two separate exceptions for Priority I areas as follows:

> (a) That, for cyclone or pulverized fired indirect heat exchangers, a maximum of forty (40) percent opacity shall be permissible for not more than one (1) six (6) minute period in any sixty (60) consecutive minutes; AND
>
> (c) For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations.

401 KAR 59:015, Section 4(2)(a) and (c). EKPC recommends that the exemption in subsection 2.b for Emission Unit 01 be revised to be consistent with the regulation.

**Division's Response:**

*The Division concurs in part. The cited regulation does not apply to the emission unit; the applicable regulation is 401 KAR 61:015. However, the quotation of Sections 4(2)(a) and (c) are correct. Section B of the permit for Emissions Unit 01, Subsection 2. Emission Limitations, has been changed to be consistent with the regulation.*

Emissions Unit 02-Indirect Heat Exchanger (Unit 2)

The opacity emission limit for Emission Unit 02, subsection 2(b) is inconsistent with the exemption found at 401 KAR 59:015, section (4)(2)(c) which states: "[f]or emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations." EKPC recommends that subsection 2(b) for Emission Unit 02 be revised to be consistent with the regulation.

**Division's Response:**

*The Division concurs and the change will be made to the permit.*

**Emissions Unit 17: Circulating Fluidized Bed Unit #4**

EKPC has several concerns regarding the treatment of particulate matter ("PM") in the draft permit.

*Filterable PM BACT for Spurlock 4 is 0.015 lb/mmBtu*
EKPC believes a filterable $PM/PM_{10}$ emission rate of 0.015 lb/mmBtu based on a 24-hour averaging period is BACT for Spurlock 4. This reflects the maximum degree of reduction achievable for Unit 4 and is consistent with other recent permitting actions. BACT Chart (Attachment 1). It is also consistent with the emission rate the vendor is willing to guarantee. Letter from ALSTOM (Mar. 31, 2006) (Attachment 2). For the reasons set forth below, EKPC believes that the filterable PM limit of 0.009 lb/mmBtu as proposed by DAQ is more stringent than BACT.

A filterable PM limit of 0.009 lb/mmBtu has not been demonstrated to be continuously achievable for the fuel to be burned by Spurlock 4. According to the definition of BACT, a BACT limit must be "achievable." Achievable means an emission limit that the source can meet on a continual basis over each averaging period for the lifetime of the facility. BACT does not require pollution reductions greater than what can be achieved with available methods. *In re Newmont Nevada Energy Investment, L.L.C.* PSD Appeal No. 05-04, slip op. at 16-17 (EAB Dec. 21, 2005). BACT is to be grounded on what is presently known about the control technology's capabilities and not speculation. *Id*. at 16.

BACT limits should be set at levels the source can meet under all reasonably foreseeable worst-case conditions. Exceeding a BACT limit is a serious violation and the penalties are severe. BACT limits are therefore not established based on what a source can achieve on its best possible day or on an average day. In a recent opinion, EPA's Environmental Appeals Board considered the stringency of the emission rate required by BACT. *Newmont* at 18 (summarizing *In re Kendall New Century Dev.*, PSD Appeal No. 03-01 (EAB Apr. 29, 2003); *In re Cardinal FG Co.*, PSD Appeal No. 04-04 (EAB Mar. 22, 2005), *In re Steel Dynamics, Inc.*, 9 E.A.D. 165 (EAB 2000), *In re Three Mountain Power, L.L.C.*, 10 E.A.D. 39 (EAB 2001)). The Board summarized its earlier opinions as standing for the proposition that "if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the 'emissions limitation' that is 'achievable' for that pollution control method over the life of the facility." *Id.* As illustrated by the stack test data from Florida for 2002 and 2003, particulate emissions are highly variable. (Attachment 3)

As indicated by the CFB JEA Northside data from Florida, particulate emissions ranged from approximately 0.002 lb/mmBtu up to 0.011 lb/mmBtu over the 2002 to 2003 period. As the limit for JEA Northside is 0.011 lb/mmBtu, this data indicates that at times the facility had little to no margin in its limit. Indeed, one test result exceeded the limit at 0.0121 lb/mmBtu. The Gilbert Unit 3 data also show variability. Two stack tests at 100% load were performed on Unit 3 on July 8, 2005. The first test indicated particulate emissions of 12.23 lb/hr (~ 0.005 lb/mmBtu), while the second indicated particulate emissions of 6.88 lb/hr (0.003 lb/mmBtu).

While these two datum points from Gilbert Unit 3 are below the proposed BACT limit by DAQ, they are an insufficient basis upon which to make a determination of what is continuously achievable and thus BACT for Unit 4. This is borne out by the JEA Northside data, where the majority of the results were less than 0.009 lb/mmBtu, but not all. Having sufficient reliable data to establish BACT is even more important in this instance given that compliance will be measured with CEMS. If something has not been achieved in practice over a sufficient period of time, it is not demonstrated to be achievable under BACT. *See In re Cardinal FG Co.*, PSD Appeal No. 04-04, slip op. at 17 (EAB March 23, 2005) (upholding determination that two to three years of operating data were insufficient).

Finally, to EKPC's knowledge, no CFB facility has a filterable PM emission limit of 0.009. EKPC is aware of claims that the Northampton facility in Pennsylvania has such a limit for total particulate, but the Pennsylvania Department of Environmental Protection has stated that the Northampton limit is 0.01 lb/mmBtu. Pennsylvania Response to Comments for Greene Energy (Attachment 4). Moreover, Northampton burns a different fuel (anthracite culm) than that proposed for Spurlock (bituminous). Pennsylvania rejected the Northampton permit limit of 0.01 for the Greene and River Hill projects (permitting them at 0.012 lb/mmBtu) citing differences in the fuels.

EKPC requests that DAQ modify the PM filterable limit to be 0.012 lb/mmBtu as follows.

> a) Pursuant to 401 KAR 59:016, Section 3(1)(b), and 401 KAR 51:017, particulate matter (PM, filterable) emissions shall not exceed 0.012 lb/mmBtu heat input based on based on 30 day CEM. Pursuant to 401 KAR 59:016, Section 6(1), compliance with the 0.012 lb/mmBtu (filterable) emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, Section 3(1)(b).

**Division's Response:**

*The Division acknowledges the comment but does not concur.*

EKPC believes a total PM limit (filterable plus condensable) of 0.012 lb/mmBtu is more stringent than BACT for Spurlock 4. As explained above, BACT has to be achievable. There is no data to support that a total PM limit of 0.012 lb/mmBtu is achievable by Spurlock 4. Indeed, EKPC is being told by its vendor that it is not achievable and will not be guaranteed. Letter from ALSTOM (date) (Attachment 2).

There is little experience in establishing condensable limits based on Best Available Control Technology ("BACT"). Indeed, in the *Newmont* decision, the EAB upheld the permitting agency's decision that BACT was not required for condensable particulate emissions. *Newmont*, slip op. at 3. EPA has also acknowledged the lack of information on condensible emissions for coal-fired boilers. *See In re AES Puerto Rico, L.P., 8* EAB 324,328 (May 27, 1999). Even though several years have passed since the *AES Puerto Rico* opinion was issued, there is still a lack of available substantial data on condensable emissions. Thus the establishment of condensable limits for new sources based on limits established and achieved for comparable existing sources is difficult, if not impossible. It is notable that EPA did not include condensable emissions in the new NSPS PM limit of 0.015 lb/mmBtu. 71 Fed. Reg. 9,866 (Feb. 27, 2006). Due to a lack of reliable data on condensible emissions and the uncertainty of the accuracy of the test methods, vendors are unwilling to provide guarantees on devices that control condensable particulate emissions.

EKPC is aware of permits recently issued in Pennsylvania (2005) with total particulate emissions limits of 0.012 lb/mmBtu (e.g., Greene, River Hill). Recognizing concerns with the accuracy of EPA Method 202 (see below) and the lack of a guarantee, Pennsylvania included a provision in the Greene permit allowing the increase of the total particulate limit to as high as 0.05 if the operator demonstrates that 0.012 lb/mmBtu is not achievable. Pennsylvania Response to Comments for Greene Energy. The situation for Greene is the same as the situation for EKPC — the questionable accuracy of Method 202 and the lack of a vendor guarantee.

As with the filterable data from Gilbert 3, the Method 202 data exhibits some variability. Again, testing using Method 202 at 100% load was conducted on July 8, 2005. Test one indicated 18.21 lb/hr (0.0073 lb/mmBtu) inorganic condensables and 3.35 lb/hr (0.0013 lb/mmBtu) organic condensables for a total of 21.56 lb/hr (0.0086 lb/mmBtu). Test 2 indicated higher inorganic emissions at 20.13 lb/hr ( 0.0081 lb/mmBtu) but lower organic emissions at 0.53 lb/hr (0.0002 lb/mmBtu), for an overall lower total condensable emissions of 20.66 lb/hr (0.0083 lb/mmBtu). When combined with the filterable test results, the proposed total PM permit limit of 0.012 lb/mmBtu would have been exceeded for test 1 at 0.0136 lb/mmBtu. While the results of these two tests are close to the proposed limit, there is no guarantee that future tests results will be this low no matter how well operated the facility is. Additionally, as discussed above, two datum points are an insufficient basis upon which to establish a limit that will apply for the life of the facility, especially given the variability exhibited in the data.

To address the lack of data with respect to condensable emissions, EKPC recommends that the permit contain an optimization study similar to that allowed in the Pennsylvania Greene permit and suggests the following language:

> b) Pursuant to 401 KAR 51:017, total particulates (PM10, filterable plus condensable) shall not exceed 0.012 lb/mmBtu based on a 3 hour performance test. The total particulates emission limit is waived for the study activity as detailed in Section D (8). Should the study indicate that 0.012 lbs/mmBtu is unachievable, then a significant revision to the permit will be required. Only the permit provisions being modified will be open for review and comment at that time. Under no case will the revised limit be greater than 0.03 lbs/mmBtu.

**Division's Response:**

*The Division acknowledges the comment but does not concur with EKP's conclusions that a rate of .012 lb/mmBtu total particulate emissions cannot be achieved at Unit 4. Further, the Division does not see a need to include an optimization study for particulate in the permit. If operating results show that the permit limit is not feasible, there are existing regulatory avenues available to pursue a change to this limit.*

EKPC recommends Section D be revised to add the following:

> (8) The permittee shall complete a study of the CFB and particulate control technology to determine the performance of the system within 36 months of commencement of commercial operation, which may be extended for an additional 12 months. The Kentucky Division for Air Quality shall have 60 days to review and approve the optimization study. Should the optimization study indicate that 0.012 lbs/mmBtu PM10 (filterable plus condensable) is unachievable, then a significant revision to the permit will be required. Under no case shall the revised BACT limit be greater than 0.03 lbs PM10/mmBtu.
>
> The PM10 (filterable plus condensable) emission limit of 0.012 lbs/mmBtu is waived prior to the completion of the study activity. This waiver is granted for a period 36 months after commencement of commercial operation. This waiver may be extended for an additional 12 months upon demonstration of need by the permittee and approval by the Division. However, the PM10 (filterable plus condensable) emissions rate shall not exceed 0.03 lbs/mmBtu during the study. If the study indicates that the 0.012 lb/mmBtu can not be achieved on a continuing basis, the applicant may file an application for a significant revision to this permit. Only the permit provisions being modified by the significant revision request will be open for review and comment at that time.

**Division's Response:**

*The Division acknowledges the comment. See the answer to the previous comment.*

*Method 202 has serious flaws.*
As set forth in the attached memorandum prepared by Ralph Roberson (RMB Consulting, Inc.), there are significant issues associated with the reliability of Method 202 to accurately measure condensible particulate emissions. (Attachment 5). No one knows exactly what Method 202 is measuring and it appears to have an indiscernible positive bias (i.e., indicates more condensable PM that is actually present).

Method 202 appears to induce conversion of $SO_2$ to $SO_4$, a reaction that normally takes place miles from the stack. Based on articles in AWMA journals, even the early field evaluations performed for EPA showed this result. Moreover, results of Method 202 testing have indicated the presence of elements, such as silica, that are not normally found behind the filter of a train sample, again suggesting that Method 202 induces the formation of such elements. Finally, much of the residue mass from Method 202 testing is unaccounted for. *See, e.g.,* UARG Petition for Reconsideration of Example Test Method 202 for Measurement of Condensable Particulate Matter Emissions from

Stationary Sources (April 20, 1992); Louis Corio & John Sherwell, *In-Stack Condensable Particulate Matter Measurements and Issues*, J. Air & Waste Manage. Assoc. 50:207-18 (Feb. 2000); *see also* Presentation by Paul Traccarella, ALSTOM Power, Trends in New Plant Emission Control Specifications (April 2005).

EPA has acknowledged the shortcomings of Method 202. Frequently Asked Questions about Method 202 from EPA Website. EPA specifically acknowledged the high degree of variability associated with Method 202 and noted that the options allowed under the method may change the mass that would be counted as condensable particulate matter. Work is underway to develop new, more accurate test methods so better data can be collected. *See e.g.,* GE Energy & Environmental Research Corporation technical paper titled "Dilution Sampling for Chemically Speciated PM2.5 Emissions from Oil, Gas & Power Combustion Sources."

Because of the issues with Method 202, EKPC proposes that Method 202 be adjusted as set forth in Mr. Roberson's memorandum. Materials in support of the concerns with Method 202 are attached (Attachment 6).

**Division's Response:** *The Division is aware of the concerns and misstatements made about Method 202. In consultation with U.S. EPA the Division is not aware of any flaws with the method if it is performed properly. EPA continues to require method 202 as the approved test method.*

*PM CEMS should not be required to demonstrate compliance.*
EKPC respectfully disagrees with the use of PM CEMS to determine compliance with the filterable PM limit. No regulatory basis exists for requiring a PM CEMS. *Newmont*, slip op. at 65-68. Moreover, the PM emissions limits established for Spurlock 4 are not based on long-term PM CEMS data. EPA recognized the necessity of such data before using PM CEMS for determining compliance when it was promulgating the PM CEMS performance specification and test procedures. As EPA stated during its rulemaking:

> PM CEMS can be sensitive to emissions variability on a real-time basis. Neither periodic short-term manual testing nor operational parametric monitoring would provide an adequate picture of this variability for standard setting purposes. Only PM CEMS data collected over a relatively long period of time would provide data sufficient for the statistical analyses necessary for establishing achievable continuous compliance emission limits.

Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring, EPA - 454/R-00-039 at 5-6 (Record cite: A-2001-10-II-A-2). Absent such data, PM CEMS should be used for compliance assurance only.

Additionally, EKPC can only obtain financing for its projects if it uses proven technologies with commercial guarantees. By mandating PM CEMS as the method for demonstrating compliance with the filterable PM emission standard, EKPC will be unable to obtain a guarantee for that standard as indicated in the letter from ALSTOM. EKPC strongly urges DAQ to reconsider requiring PM CEMS to demonstrate compliance. PM CEMS should instead be specified for compliance assurance purposes. Materials in support of the concerns with PM CEMS are attached (Attachment 7).

**Division's Response:**

*The Division acknowledges the comment but does not concur. The performance specification for operation of a PM-CEM has been issued.*

*Sulfur Dioxide ($SO_2$)*
EKPC disagrees with DAQ's reduction of the $SO_2$ BACT limit from the proposed 0.18 lb/mmBtu to 0.15 lb/mmBtu in the draft permit. DAQ provides no justification for this reduction. EKPC determined that its proposed combination of control technology (CFB with limestone injection and a dry scrubber) will be capable of achieving 98% removal, which represents the maximum degree of reduction with a margin of safety achievable for Unit 4 with demonstrated technology. Based on design coal, that removal efficiency translates into a limit of 0.18 lb/mmBtu. Moreover, EKPC's vendor will not provide a commercial guarantee for a removal efficiency greater than 98%. Moreover, decreasing $SO_2$ will impact the ability to achieve a lower $NO_x$ limit consistently.

**Division's Response:**

*The Division acknowledges the comment. BACT for $SO_2$ in this permit is an emission rate,not a control efficiency. EKP's selection of coal to use in Unit 4 is a business decision within EKP's control..*

*Nitrogen Oxides ($NO_x$)*
EKPC is concerned that requiring a significant modification to revise the permit if it is determined that 0.07 lb $NO_x$/mmBtu is not achievable will lead to the reopening of the entire permit. To avoid that circumstance, EKPC proposes that Emission Unit 17 permit condition 2(g) be revised as follows:

> g) Pursuant to 401 KAR 51:017, nitrogen oxides emissions shall not exceed 0.07 lb/mmBtu based on a thirty (30) day rolling average. The $NO_X$ emission limit is waived for the specific SNCR optimization study activity as detailed in Section D ( 6 and 7). Should the optimization study indicate that 0.07 lbs/mmBtu is unachievable, then a significant revision to the permit will be required. Only the permit provisions being modified by the significant revision request will be open for review and comment at that time. Under no case will the revised limit be greater than 0.09 lbs/mmBtu.

EKPC recommends Section D (6) be revised as follows:

> 6. The permittee shall complete a study of the CFB to determine the optimized performance of the SNCR system within 18 months commencement of commercial operation(40 CFR 72.2). The Kentucky Division for Air Quality shall have 60 days to review and approve the optimization study. Should the optimization study indicate that 0.07 lbs/mmBtu is unachievable, then a significant revision to the permit will be required. Only the permit provisions being modified by the significant revision request will be open for review and comment at that time. Under no case shall the revised BACT limit be greater than 0.09 lbs NOx/mmBtu.

**Division's Response:**

*The Division acknowledges the comment but does not concur.*

*Fluoride*
The fluoride emission limit in the permit of 0.000047 lb/mmBtu is for particulate fluoride only. It does not include hydrogen fluoride (HF) emissions.

EKPC requests that Emission Unit 17 permit condition 2(k) be modified as follows to include HF emissions.

> k) Pursuant to 401 KAR 51:017, particulate fluoride emissions shall not exceed 0.00047 lb/mmBtu based on a three hour rolling average.

**Division's Response:**

*The Division acknowledges the comment but does not concur. The permit limit for fluoride emissions will not be changed.*

*Startup, Shutdown and Malfunction Emissions*
EKPC request the Division to clarify that all the permit limits listed in Section 2 for Emission Unit 17 (Spurlock 4) do not apply during startup, shutdown and malfunction events. This is not intended as a blanket waiver of BACT under these events but a recognition that the CFB and control technology will not be able to control emissions to BACT levels during such time. EKPC proposes the following revision to Emission Unit 17 permit condition 2(o).

> o) Pursuant to 401 KAR 401 KAR 59:016 Section 6(3), PM and NOx emission standards apply at all times except during periods of startup, shutdown or malfunction. The sulfur dioxide emission standard under Section 4 applies at all times except for periods of startup, shutdown or malfunction. Pursuant to 40 CFR 60.47a, mercury emission standard applies at all times except during periods of startup, shutdown or malfunction. The CO, VOC, fluoride, and sulfuric acid mist emissions standards apply at all times except for periods of startup, shutdown or malfunction. Pursuant to 401 KAR 51:017, the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such events.

**Division's Response:**

*The Division acknowledges the comment but does not concur. Regulation 401 KAR 50:055 governs compliance requirements during shutdown, subsequent startups, and malfunctions.*

**Sierra Club Comments:**

**I. Spurlock Unit 1**

**A. Particulate Matter Emissions from Unit 1**

The Draft Permit establishes a limit on particulate matter emissions of 0.14 pound per million Btu heat input (lb/MMBtu), "based on a three hour average." Draft Permit § B.2.a., page 2. This limit is based on 410 KAR 61:015, sec. 4(1) and Appendix A. However, the emission standard in 410 KAR 61:015, sec. 4(1) and Appendix A are set forth in pounds per million Btu input, without an averaging period. Therefore, the averaging period for the limit in 401 KAR 61:015, sec. 4(1) is instantaneous. While compliance with PM limits has traditionally been tested through stack testing, which inherently provides a three-hour average, that 3-hour averaging period is an incidental consequence of the test method and not provided by the underlying limit. This is an important distinction when compliance monitoring other than a traditional stack test is used. Such other compliance monitoring methods must ensure compliance with the instantaneous PM limit.

**Division's Response:**

*The Division acknowledges the comment but does not concur. 401 KAR 61:015, Section 7(c) requires Reference Method 5 as the performance test used to demonstrate compliance with the particulate matter limit, which requires sampling over a 3-hour period. It would be unreasonable to establish an emission limit that is inconsistent with the test to demonstrate compliance.*

The CAM plan required by the Draft Permit for Unit 1 allows EKPC to determine compliance with the <u>instantaneous</u> PM limit from 401 KAR 61:015, section 4 and Appendix A by a <u>three-hour average</u> of COM values. Draft Permit § B.4.b.1., page 3. This effectively changes the underlying limit from an instantaneous limit to a three hour average. This is impermissible. Moreover, the Statement of Basis ("SOB") for the Draft Permit fails to provide any reason for the Division's determination that a three hour average of COM data reliably demonstrates compliance with an instantaneous PM limit. The CAM plan must be revised to ensure that Unit 1 is complying with its permit limit at all times, not merely on a three hour average. This can be done by establishing a maximum COM value that cannot be exceeded, or by another method. The Division must also explain its rationale for the monitoring chosen in the SOB.

**Division's Response:**

*The Division acknowledges the comment but does not concur. The contention that the PM limit is instantaneous is inconsistent with the approved compliance demonstration method. The three-hour averaging of COM data is consistent with the underlying particulate matter limit. Since the particulate matter limit is not instantaneous, no changes are necessary to the Draft Permit or the CAM plan.*

*Further, the applicable requirements upon which the limits and conditions in the permit are based are contained in the permit. They are also contained and explained in the Statement of Basis, along* *with the reasoning for how the Division applied the requirements to Spurlock Unit 4. The Division does not agree that 40 CFR 70.7(5), the regulatory requirement concerning the contents of the Statement of Basis, requires the level of detail (i. e., an explanation of the rationale for selected monitoring methods) requested in the comment.*

**B. Visible Emissions**

The Draft Permit states that emissions from Unit 1 "shall not exceed 20 percent opacity based on a six-minute average except that a maximum of 40 percent opacity is allowed for a period or aggregate of periods not more than six minutes in any 60 minutes during building a new fire, cleaning the firebox, or blowing soot." Draft Permit § B.2.b., page 2. This limit is purportedly based upon 401 KAR 61:015, sec. 4(2). Id. However, the underlying emission limit does not provide for an "aggregate of periods" to exceed 20% opacity. Allowing the facility to exceed 20% opacity in any aggregate of periods is illegal and impractical. The actual limit in 401 KAR 61:015, sec. 4(2) is 20% opacity, except "maximum of forty (40) percent opacity shall be permissible for not more than one (1) six (6) minute period in any sixty (60) consecutive minutes…" Notably, the exemption up to 40% opacity applies for a single six minute period, and not for any aggregate of six minute periods. Moreover, because an opacity COM will measure opacity in six-minute averages, it is not practicable to aggregate emission from various six-minute blocks within any hour period. See e.g. Draft Permit § B.6.ii., page 5 (opacity reported in six minute averages).

**Division's Response:**

*The Division concurs and the permit has been changed accordingly. The phrase "aggregate of periods" was inadvertently carried-over from EKPC's previous permit, in which Regulation 7 was applicable. Regulation 7.4(3) states in part "...for a period or periods aggregating not more than six minutes in any sixty minutes...". Rebuilding the electrostatic precipitator resulted in 401 KAR 61:015, Section 4 being the applicable regulation instead of Regulation 7 for opacity and particulate matter.*

The opacity limit for Unit 1 must be revised to a 20% opacity limit, with the exception of one six-minute average in which emissions cannot exceed 40% opacity. Additionally, the Division should clarify that the monitoring requirement in Draft Permit § B.4.a., page 2—requiring EKPC to conduct a Method 9 test or accept the readout from the COMS— is a requirement of the CAM rule to ensure immediate correction of excess emissions. It is not a limit on the type of evidence that can be used to enforce the underlying limit. For example, any readout from the COMS showing a violation of the visible emission limit can be used to enforce the permit, regardless of whether the owner conducts an additional Method 9 test or not. Moreover, COM results are more accurate than Method 9 and Method 9 testing should not be used instead of COM data to determine compliance. Sierra Club v. Pub. Serv. Co. of Colo., 894 F.Supp. 1455, 1460 (D.Colo. 1995) (relying on Method 9 alone "would be contrary to the Act's purpose and undermine congressional intent."); Sierra Club v. Georgia Power Co., 365 F. Supp. 2d 1297, 1307-08 (N.D. G a. 2004) (COMS "data are credible, prima facie evidence of the opacity violations…").

In addition to the CAM requirements in the permit, the Permit must also contain sufficient monitoring to assure continuous compliance. 40 C.F.R. § 70.6(a)(3). An owner or operator, or an inspector, must be able to immediately determine whether the source is in compliance with all applicable limits. 40 C.F.R. § 70.6(3)(a)(3)(B). When the underlying regulation does not establish a sufficient monitoring requirement, the Title V permit must establish a monitoring method that is capable of immediately demonstrating compliance or non-compliance. Id.

The Draft Permit must be revised to specify that (once an opacity based indicator value of PM emissions is established through a stack test) any exceedance of the opacity-indicator value is a violation of the PM limit, regardless as to whether the permittee "accept[s] the concurrent readout of the COM" or conducts a Method 9 test under Draft Permit § B.4.a., page 3.

**Division's Response:**

*As noted on page 30 of the Statement of Basis in the section about Credible Evidence: "This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has only adopted the provisions of 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12 into its air quality regulations."*

*It is not clear what is meant by "immediately demonstrating compliance", nor does the referenced cite to 40 CFR § 70.6(3)(a)(3)(B) contain any such requirement, but rather permits the use of averaging and other statistical conventions consistent with the applicable requirements. The monitoring and testing methods specified in the permit are consistent with requirements specified in 401 KAR 61:015 and 40 CFR Part 64 CAM. It should be noted that 401 KAR 50:055 Section 2(3) specifies that compliance with opacity standards shall be determined by Method 9, except as may be provided for by administrative regulation for a specific category of sources, and that the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence.*

Additionally, the Permit should state that the exemption from the "good housekeeping" requirements of § B.4.a., page 3, which exempt the source from having to "accept the readout from the COM and perform an inspection" or to perform a Method 9 test when excess emissions occur during startup, shutdown and exempted periods, does not exempt the source from the opacity (or PM) emission standard during startup and shutdown periods. The applicable PM and visible emission limits do not exempt excess emissions during startup and shutdown. Moreover, the permit should contain sufficient monitoring during startup and shutdown periods to determine compliance during all periods, including startup, shutdown and malfunction.

**Division's Response:**

*The Division concurs that this language was not intended to provide an exemption that did not already exist in the applicable regulations. A review of Kentucky regulations pertaining to indirect heat exchangers would reveal that different exemptions apply depending upon the type of heat exchanger, such as waterwall, cyclone, pulverized fired, stoker fired, stationary grates, and when the unit was constructed. Therefore, the above referenced language has been changed to "Excluding…. exempted time periods..." to make clear that this language is not intended to specify the exemptions, but rather to acknowledge that if an exemption applies, the specified investigative and remedial actions are not required.*

Additionally, every Title V permit must "assure[] compliance by the source with all applicable requirements." CAA § 504(a); 40 C.F.R. § 70.1. "Applicable requirements" include SIP and permit requirements. 40 C.F.R. § 70.2; see also, 401 KAR 51:017. As an applicant for a Title V permit, EKPC must disclose all applicable requirements and any violations at the facility. 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(i), (5), (8); 401 KAR 52.020, secs. (3)(1)(b), (4)(1), and (5). If EKPC will not be in compliance with any applicable requirement(s) at the time of permit issuance, the permit application must contain a narrative description of how the source intends to come into compliance with the requirements and a proposed compliance schedule for coming into compliance. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.5(c)(8)-(9); 401 KAR 52.020, sec. 5(8); In the Matter of Onyx Environmental Services, Order Responding to Petitioners' Request That the Administrator Object to Issuance of a State Operating Permit, pp. 6-7 (Adm'r Feb. 1, 2006). EKPC has violated the visible emission limit for Spurlock Unit 1 on an intermittent and repeating basis. Because a large number of the Division's compliance records for Spurlock have been destroyed, Sierra Club was only able to obtain some compliance records for the period since January, 2004.[1] However, based on the limited records available, EKPC violated the applicable visible emissions[2] standard at Spurlock Unit 1 as follows[3]:

| | | |
|---|---|---|
| From 1/1/2004 to 4/1/2004 | 105 six-minute periods of excess emissions | 0.48% of operating time in violation. |
| From 4/1/2004 to 7/1/2004 | 154 six-minute periods of excess emissions | 0.98% of operating time in violation |
| From 4/1/2005 to 7/1/2005 | 47 six-minute periods of excess emissions (and 48 minutes of missing opacity data) | 0.22% of operating time in violation (and 48 mintues of missing opacity data) |
| From 10/1/2005 to 1/1/2006 | 37 six-minute periods of excess emissions (and 78 minutes of opacity data missing) | 0.18% of operating time in violation (and 78 minutes of opacity data missing) |

**Division's Response:**

*An Agreed Order was signed on September 29, 2005 which, among other things, includes a requirement for EKPC to submit an Operation and Maintenance Plan (OMP) to ensure compliance at both the Cooper and Spurlock stations. This OMP was filed with the Division on November 2, 2005.*

*The Division's Field Operations Branch conducted a review of the 2005 Fourth Quarter Continuous Emissions Monitoring Report for the Spurlock station on February 6, 2006, and no violations were found.*

*Footnote 2 of the Sierra Club comments indicated that there is a discrepancy between the opacity limit on the emission reports and that which is contained in the Draft Permit. The Draft Permit reflects a change from the previous permit as a result of the electrostatic precipitator replacement.*

**C. SO2**

The SO2 limit for Unit 1 is expressed as a twenty-four hour average. Draft Permit § B.2.c., page 2. This does not reflect the underlying regulatory limit. The regulatory limit is expressed on an instantaneous basis (pounds per Million Btu).[4] The Title V permit cannot change the averaging time of the underlying limit. The Draft Permit must be changed to express the SO2 emission limit for Unit 1 as an instantaneous limit.

**Division's Response:**

*Appendix B to 401 KAR 61:015 specifies that "All Standards are twenty-four (24) hour averages."*

**II. Spurlock Unit 2**

**A. Operating Limitations**

The Draft Permit states that there are no operating limitations on Unit 2. This is incorrect. When EKPC applied for a permit to construct Unit 2 in January 1976, EKPC represented that it would construct and operate a pulverized coal unit with a maximum heat input of 4850 million Btu/hour. When EKPC asked to revise the maximum heat rate for Unit 2 from 4,850 million Btu/hour to 5,355 MMBtu/hr the Division rejected the request and stated that a PSD permit was required for such modification. See Ex. 2 at pp. 44-47. EKPC has not applied for, nor been issued a pre-construction permit for a heat rate change to Unit 2. Therefore, the Permit must include the existing operational limit of 4,850 million Btu/hour.

**Division's Response:**

*U.S. EPA currently has an enforcement action pending on this issue. Upon resolution of that action, the Division will revisit this issue if necessary.*

**B. Particulate Matter Emission Limits**

The Draft Permit establishes a limit on particulate matter emissions of 0.1 pound per million Btu heat input, "based on a three hour average." Draft Permit § B.2.a, page 6. This limit is based on 410 (sic) KAR 61:015, sec. 4(1)(b) and Appendix A. Id.. As noted above for Unit 1, the emission standards in 410 KAR 61:015, sec. 4(1) and Appendix A are set forth in pounds per million Btu, without an averaging period. Therefore, the averaging period is an instantaneous average. The fact that compliance was historically determined only by stack testing-- which inherently used a three-hour average-- does not change the fact that the underlying limit is an instantaneous limit. The Permit must be revised to change the PM limit for Unit 2 from a three hour average to an instantaneous limit.

Additionally, the CAM plan required for Unit 2 allows the source to determine compliance with the instantaneous PM limit from 401 KAR 61:015, section 4 and Appendix A by a three-hour average of COM values. Draft Permit § B.4.b.1., page 7. This impermissibly changes the limit from an instantaneous limit to a three hour average. The SOB also fails to provide any statement or description of why the Division believes that a three hour average of COM data reliably demonstrates compliance with an instantaneous PM limit.

**Division's Response:**

*See the response to similar comments made about Unit 1.*

**C. Visible Emission Limitations**

The Division should clarify that the monitoring requirement in Draft Permit § B.4.a., page 7—requiring EKPC to either conduct a Method 9 test or accept the readout from the COMS— is a requirement to ensure good operating practices and does not restrict the use of the COM reading for enforcement. In other words, EKPC's election to conduct a Method 9 test does not prevent an enforcement action based upon the COM data. Similarly, the Permit must specify that once an indicator value for opacity is determined through a stack test, any exceedance of that indicator value is a violation of the PM limit, regardless as to whether the permittee "accept[s] the concurrent readout of the COM" or conducts a Method 9 test under Draft Permit § B.4.a., page 7.

The Permit should also clarify that the exemption from the requirement to either "accept the readout from the COM and perform an inspection" or perform a Method 9 test during startup, shutdown and exempted periods, does not exempt the source from the opacity (or PM) emission standard during startup and shutdown periods.

As noted above, every Title V permit application must disclose violations at the facility, a narrative description of how the source intends to come into compliance with the requirements and a proposed compliance schedule for coming into compliance. 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(i), (5), (8)-(9); 401 KAR 52.020, secs. (3)(1)(b), (4)(1), and (5); In the Matter of Onyx Environmental Services, pp. 6-7. EKPC has violated the visible emission limit for Spurlock Unit 2 on an intermittent and repeating basis. Because the Division's records have been destroyed, Sierra Club was only able to obtain some compliance records for the period since January, 2004. However, based on these limited records, EKPC violated the applicable 20% opacity visible emission standard at Spurlock Unit 2 as follows[5]:

| | | |
|---|---|---|
| From 1/1/2004 to | 103 six-minute periods of | 0.48% of operating |

| | | |
|---|---|---|
| 4/1/2004 | excess emissions | time in violation. |
| From 4/1/2004 to 7/1/2004 | 79 six-minute periods of excess emissions | 0.37% of operating time in violation |
| From 4/1/2005 to 7/1/2005 | 122 six-minute periods of excess emissions (and 54 minutes of missing opacity data) | 0.84% of operating time in violation (and 54 minutes of missing opacity data) |
| From 7/1/2005 to 10/1/2005 | 2 six-minute periods of excess emissions | 0.01% of operating time in violation |

These violations are recurring and can be expected to recur absent a change in equipment and/or operations. Therefore, the violations will not be corrected by the time of permit issuance. The violations are not disclosed in the application, a compliance plan is not proposed in the application, and the Draft permit does not address these violations.

**Division's Response:**

*See the response to similar comments made about Unit 1.*

**D. PSD Limits for Unit 2**

Every Title V permit must "assure compliance by the source with all applicable requirements." CAA § 504(a); 40 C.F.R. § 70.1. "Applicable requirements" include SIP requirements and preconstruction requirements, including the requirement to obtain a preconstruction permit and apply best available control technology. 40 C.F.R. § 70.2; 401 KAR 51:017. Further, every Title V permit application must disclose all applicable requirements and any violations at the facility. 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(i), (5), (8); 401 KAR 52.020, secs. (3)(1)(b), (4)(1), and (5). For applicable requirements, including new source requirements and preconstruction permitting requirements, for which the source is not in compliance at the time of permit issuance, the source's application must provide a narrative description of how the source intends to come into compliance with the requirements. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.5(c)(8)-(9). The application must also include a compliance schedule for any applicable requirements for which the source is not in compliance. 40 C.F.R. § 70.5(c)(8)(iii); 401 KAR 52.020, sec. 5(8). Additionally, EKPC is required to certify its compliance with its application and annually. 501 KAR 52.020, secs. 5(9), 21, 23. The U.S. EPA Administrator has described these requirements as follows:

40 C.F.R. § 70.5(c)(8)(iii)(C) and 70.6(c)(3) require that, if a facility is in violation of an applicable requirement and it will not be in compliance at the time of permit issuance, its permit must include a compliance schedule that meets certain criteria. For sources that are not in compliance with applicable requirements at the time of permit issuance, compliance schedules must include 'a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance.' 40 C.F.R. § 705(c)(8)(iii)(C). In the Matter of Onyx Environmental Services, Order Responding to Petitioners' Request That the Administrator Object to Issuance of a State Operating Permit, pp. 6-7 (Adm'r Feb. 1, 2006).

The Division's "Permit Application Summary Form" for the Draft Permit incorrectly indicates that the source is not out of compliance. See Ex. 3, p.1. It also indicates that no compliance certification was signed by EKPC, and that there was no compliance schedule included in the application. However, the Division's "Permit Statement of Basis" notes that, in fact, "U.S. EPA has brought an action in U.S. District court concerning EPA's allegation of past NSR violations on emission unit 02." Statement of Basis p. 1. The Statement of Basis further notes that "[u]pon resolution of the [NSR violations] raised, the Division may be required to reopen this permit." Id. The Division cannot postpone its legal obligation to determine whether the facility filed a complete permit application- including disclosure of violations and a proposed compliance schedule- until after an enforcement action. EKPC has undergone major modifications at Spurlock Unit 2 and has violated its Title V permit by failing to operate Unit 2 pursuant to its permit applications. EKPC has also violated its permit by failing to disclose its NSR violations in the periodic compliance reports filed with the Division. These violations must be disclosed. EKPC must propose a compliance schedule and the permit must include a compliance schedule to bring Spurlock into compliance with applicable NSR permitting requirements and compliance certification requirements.

In January 1976, EKPC applied for a construction permit for Unit 2. See Ex. 2, pp. 8-14. In its application, EKPC represented that it would construct and operate a pulverized coal unit with a maximum heat input of 4850 million Btu/hour. Ex. 2, p. 12. On November 10, 1982, EPKC was issued a Title V operating permit which required EKPC to operate Unit 2 at or below the maximum hourly heat input of 4850 MMBtu/hr. Ex. 2, p. 37. In August, 1992, EKPC began supplying steam from Unit 2 to another facility, Inland Container Corp., despite the fact that EKPC's 1976 construction permit application for Unit 2 stated that all steam generated at Unit 2 would be used to generate electricity. Ex. 2, p. 3. By operating Unit 2 to supply steam to Inland Container, EKPC violates the requirement to operate in accordance with its application. 40 C.F.R. § 52.21(r)(1). Moreover, the increased steam demand created by connecting to Inland Container Corp and supplying steam also violated the Clean Air Act because it resulted in an unpermitted significant net emission increase.

Furthermore, the physical changes necessary to provide steam to Inland were not permitted by the Title V permit, and therefore constitute a physical change subject to PSD permitting. 40 C.F.R. § 52.21(b)(2)(iii)(f). Additionally, according to the U.S. EPA, EKPC has begun operating Unit 2 at rates far in excess of 4,850 MMBtu/hr. EKPC asked for the Division's permission for this change (from 4,850 MMBtu/hr to 5,355 MMBtu/hr) in a letter dated December 15, 1993. Ex. 2, p. 40. However, the Division warned EKPC that such an increase in heat input rate, without a PSD preconstruction permit, violates the Clean Air Act. Ex. 2, p. 42. Despite this warning from the Division, it appears that EKPC has, in fact, increased the maximum heat rate for Unit 2 without a preconstruction permit. This operational change, which was prohibited by EKPC's existing permits, violates 401 KAR 51:017, sec. 8 because it constitutes an unpermitted major modification. See also 42 U.S.C. § 7475(a). The Division has already reached this conclusion in its letter to EKPC.

Furthermore, EKPC made significant modifications to Unit 2 which increased the peak generation capacity from 508 to 585 MW. Based on EPA's analysis, EKPC anticipated, and subsequently experienced, an increase in utilization of Unit 2. Ex. 2, pp. 3-4. The anticipated increase in utilization correlated to a significant net increase in pollutants regulated under the Clean Air Act. Id. Despite this anticipated significant net emissions increase, EKPC undertook a physical change without a pre-construction permit by replacing a high-pressure turbine with a turbine of a new and different design. Id.

EPA explicitly found that the modifications (including operational and physical changes) discussed above were undertaken without the required pre-construction permits and, therefore, that EKPC is in violation of the Clean Air Act. Ex. 2. EPA issued a Notice of Violation for these violations at the Spurlock Generating Station. Id.. EPA also filed an enforcement action against EKPC in federal court for these violations. United States v. East Kentucky Power Coop., Case No. 04-34-KSF (E.D.Ky.). An NOV and commencement of a civil suit conclusively demonstrates "non-compliance for purposes of the Title V review process." New York Public Interest Research Group v. Johnson, 427 F.3d 172, 180 (2nd Cir. 2005). The NOV is EPA's official finding that Spurlock is in violation of PSD preconstruction permitting requirements. Id. at 181; 42 U.S.C. § 7413(a)(1). A failure to require compliance with PSD requirements that were triggered by unpermitted major modifications is a deficiency in the Title V permit. See In re Onyx Environmental Services, supra, p. 8. Therefore, the permit cannot issue unless and until the following:

1) EKPC submits a complete application, including a sworn disclosure of its violations of PSD and its Title V permit;

2) EKPC submits a compliance schedule sufficient to bring Unit 2 into compliance with all requirements of the Clean Air Act; and

3) The Division has reviewed, initially approved, and submitted a revised draft permit for public comment which includes a compliance schedule that brings Unit 2 into compliance with the Clean Air Act.

Additionally, because Unit 2 underwent a major modification, its emissions consume increment. Before the Division can issue a PSD permit for Unit 4 EKPC must demonstrate that the allowable emissions from Unit 4 "in conjunction with all other applicable emissions increases or reductions… shall not cause or contribute to air pollution in violation of… [a]n applicable maximum allowable increase over the baseline concentration in any area." 401 KAR 017, Section 9. The "baseline concentration" is the concentration that existed in the baseline date when the minor source baseline date was established, which expressly excludes "[a]ctual emissions at a major source, which result from construction commencing after the major source baseline date…," regardless of whether the major source commenced construction before or after the minor source baseline. 401 KAR 51:001, Section 1(22). The major source baseline date is January 6, 1975 for PM and SO2 and February 8, 1988 for NOx. 401 KAR 51:001, Section 1(119). In other words, because Unit 2 commenced construction (which includes modifications, 401 KAR 51:001, Section 1(52)) after the major source baseline date as set forth in EPA's NOV, the emissions from Unit 2 must be added to the emissions consuming baseline. Neither EKPC nor the Division did so in modeling to determine whether the emissions from Unit 4 will violate increment pursuant to 401 KAR 51:017, Section 9. This must be done before the PSD permit can issue for Unit 4 and before the Title 5 permit can issue for

Spurlock Generating Station.

**Division's Response:**

*The Division is aware of this proceeding. Upon settlement or judicial ruling, and if necessary, the Division will incorporate appropriate terms and conditions into this permit.*

**III. Spurlock Unit 3**

**A. Operational Limits**

The Draft Permit correctly includes an operational limit for Unit 3, requiring EKPC to "install control devices selected as BACT." Draft Permit § B.1., page 11. However, the permit must also include a requirement to construct and operate Unit 3 according to the plans and specifications submitted as part of the pre-construction permit application. 401 KAR 51:017, sec. 16. This includes, but is not limited to, the fuel, control equipment, and maximum heat rating included in the permit application. The Permit must be revised to include these requirements.

**Division's Response:**

*The permittee is constrained to build and operate in accordance with all terms and conditions contained in the permit. The permit is written based on the application, which must be complete and accurate in order to comply with the requirements of 401 KAR 52:020. These are fundamental precepts of the permitting program, and the Division does not concur with a need to further explain in the permit that the permittee must adhere to their application and comply with their permit.*

**B. PSD Limits for Unit 3**

BACT limits established in prior Title I permits can be revisited in Title V permitting processes if it is established that the historic BACT determination was erroneous. <u>In the Matter of Chevron Products Co., Richmond, California</u>, Petition No. IX-2004-08 at 11-12 and n.13 (remanding a Title V permit to the state permitting agency because a PSD permit issued ten year prior contained an erroneous BACT limit). The PSD permit for Unit 3 contains a number of erroneous BACT limits which must be corrected before a Title V permit can issue for the Spurlock Generating Station.

**1. Visible Emissions (Opacity)**

The Draft Permit fails to contain a visible emission BACT limit for PM and SAM. Draft Permit § B.2.b., page 11. Instead, the permit's only visible emission limit for Unit 3 is a limit based upon 401 KAR 59:016, sec. 3(2), which is the New Source Performance Standard. This is insufficient to satisfy the requirements of 401 KAR 51:017, Section 8. Any new or modified major source, including Spurlock Unit 3, must have a permit requiring BACT. 401 KAR 51:017, sec. 8. BACT is expressly defined as an "emissions limitation <u>including a visible emission standard</u>," for each criteria pollutant. 401 KAR 51:001, Section 1(25) (emphasis added); 40 C.F.R. § 52.21(b)(12). However, the Draft Permit fails to include limits that include visible emission standards for PM and SAM (which are two of the pollutants that create visible emissions) based on the maximum degree of reduction achievable. Id. Although BACT limits are typically expressed as emission rates (i.e., pounds per hour or pounds per million Btu heat input), the plain language of the Clean Air Act, as well as 401 KAR 51:001 Section 1(25) defines BACT as expressly "including a visible emission standard." See 42 U.S.C. § 7479(3). Other coal plants have BACT limits that include visible emission limits. For example, the Springerville facility in Arizona has a BACT limit of 15 percent opacity, and the Mid-America facility in Council Bluffs has an opacity limit of 5 percent. See Iowa DNR Permit No. 03-A-425-P, §10a (Permit available online at http://aq48.dnraq.state.ia.us:8080/psd/7801026/PSD_PN_02-258/03-A-425-P-Final.pdf, last visited October 28, 2005). The Fort James (Fort Howard) paper mill in Green Bay, Wisconsin, has a 10% opacity limit, based on BACT for its 500 MW CFB boiler. See Preconstruction Review and Preliminary Determination on the Proposed Construction of a Circulating Fluidized Bed Combustion Boiler for Fort Howard Paper Company to Be Located At 1919 South Broadway, Green Bay, Brown County, Wisconsin, p. 8 (May 26, 1988), attached as Ex. 4 hereto. The Draft Permit must be revised to include a visible emission limit for PM and SAM of no more than 10% opacity, and should include a requirement that Spurlock undertake an optimization study to determine the final opacity limit.

**Division's Response:**

*The BACT determination for Unit 3 was made during a previous permitting action and there is no basis for performing a new BACT analysis at this time.*

**2. Sulfur Dioxide Limits**

The SO2 limit for Unit 3 does not satisfy the requirement to install BACT, based on BACT at the time that Unit 3 was constructed (commencing June, 2002, according to the Draft Permit). The AES Puerto Rico permit was issued well before Unit 3 commenced construction. The AES Puerto Rico permit establishes a 0.022 lb/MMBtu SO2 limit, based on a three hour average, for two coal-fired CFB units. See Ex. 5, p. 3. This is presumed to be BACT for Unit 3 because EKPC has not demonstrated that it is not technologically feasible or cost effective, nor that it causes unique adverse energy or environmental collateral impacts. NSR Manual at B.24; Newmont Nevada Energy Investments, LLC, TS Power Plant, PSD Appeal No. 05-04, Slip Opinion at 16 (EAB Dec. 21, 2005). Moreover, other BACT limits set for coal fired CFB units in California prior to the Unit 3 preconstruction permit established lower SO2 emission rates.

- Pyropower Corp. received a SO2 limit of 0.039 lb/MMBtu for a 49.9 MW coal fired CFB in 1986. See Ex. 6.

- BMCP (Thomas Oil) received an SO2 limit of 0.039 lb/MMBtu (96% control) for a coal fired CFB in 1986. Id.

- Cogeneration National Corp. received an SO2 limit of 95% control for two coal fired CFB units in 1985. Id.

The SO2 limit for Unit 3 did not constitute BACT for Unit 3 at the time Unit 3 commenced construction. Therefore, the Draft Permit contains a deficient limit and must be corrected. A correct BACT limit for Unit 3 would be much lower, resulting in significantly less air pollution.

**Division's Response:**

*See the response to comment B. 1.*

**3. Particulate Matter Limits**

The Draft Permit contains a PM limit for Unit 3 of 0.015 lb/MMBtu. This purports to be a BACT limit. However, BACT for PM emissions from a coal fired CFB unit at the time that Unit 3 was constructed is much lower. Pennsylvania issued a PSD permit in April 1995 to the Northampton Generating Company with a total PM10 limit of 0.0088 lb/MMBtu. Ex. 3, pp. 13-14. This facility is a 1,146 MMBtu/hr circulating fluidized bed boiler. Compliance testing in February 2001 reported total PM10 emissions of 0.0045 lb/MMBtu. Contrary to the common misconception that the permit limit is for filterable PM only and that the compliance test only included filterable PM, the 0.0088 lb/MMBtu Northampton permit limit and the compliance test include some condensible PM. The Northampton permit requires testing by "Method 5," which refers to Pennsylvania Method 5. Unlike USEPA Method 5, which only tests for filterable particulate matter, Pennsylvania's "Method 5" includes both front half and backhalf emissions (i.e., both filterable and condensible PM). See Ex. 8. In response to requests for more information, the Pennsylvania DEQ confirmed that the compliance tests for Northampton included condensible fraction PM in the backhalf of the sampling train. Id. Because Northampton is achieving lower emission rates, and EKPC has not shown any reason why such lower emission rates cannot be achieved at Spurlock 3, the BACT limit for total PM emissions at Spurlock 3 must be revised to 0.0088 lb/MMBtu. NSR Manual at B.24 ("[i]n the absence of a showing of differences between the proposed source and previously permitted sources achieving lower emission limits, the permit agency should conclude that the lower emission limit is representative for that control alternative."); Newmont Nevada Energy Investments, Slip Opinion at p. 16 (E.A.B. 2005).

**Division's Response:**

*See the response to comment B. 1.*

**4. Nitrogen Oxides Limit**

The Draft Permit contains a permit limit of 0.07 to 0.1 lb/MMBtu (depending on an initial optimization study) for NOx from Unit 3. This is purportedly BACT for NOx when Unit 3 was constructed. However, BACT in 2002 (when Unit 3 commenced construction) was much lower. A number of coal-fired CFB units in California had lower BACT limits for NOx before 2002. The BMC facility had a NOx BACT limit of 0.039 lb/MMBtu for its coal-fired CFB boiler well before the Spurlock 3 permit was issued. See Ex. 6. The 0.0039 lb/MMBtu limit for NOx at the BMC facility represents 80% control of NOx from that facility. Id. As noted below for Unit 4, other coal-fired CFB units were subject to lower NOx limits than Spurlock 3 prior to the initial Spurlock 3 permit. EKPC has not shown any reason why it cannot achieve these lower limits. Therefore, the BACT limit for Unit 3 was in error when initially issued and must be corrected before the Title V permit can issue.

**Division's Response:**

*See the response to comment B. 1.*

**5. Sulfuric Acid Mist Limit**

The Draft Permit contains a SAM limit of 0.005 lb/MMBtu on a thirty day average. Draft Permit p. 12. This purports to be a BACT limit. It is not. BACT for SAM in 2002, when the Unit 3 preconstruction permit was issued, was much lower. The AES Puerto Rico permit for a similar coal-fired CFB unit was much lower and was issued well before the Unit 3 permit. The AES Puerto Rico permit established a SAM emission limit from a similarly sized CFB boiler to Unit 4 of 0.0024 lb/MMBtu. See Ex. 5, p. 5. Because this emission limit was established for a similar sized CFB unit, it is technologically feasible, and assumed to be cost effective and BACT for Spurlock 3. NSR Manual at B.24. The Permit must be modified to include correct BACT limits for Unit 3.

**Division's Response:**

*See the response to comment B. 1.*

**6. The Limits for Unit 3 Are Not Enforceable.**

The Draft Permit should clarify the test method to be used to measure fluoride in the stack gases, as required by section 3(b) on page 13 of the Draft Permit. Additionally, because the Draft Permit relies on the fluoride in the coal as an indicator of fluoride emissions, the Permit must state that an exceedances of the fluoride indicator value is a violation of the fluoride limit in the Permit. Additionally, it appears that the Draft Permit fails to establish any test methods for the initial stack test of Unit 3. This should be clarified in the Permit.

**Division's Response:**

*Section 3(b) specifies that a performance test shall be conducted for particulate emissions, not hydrogen fluoride. Section 3(e) specifies the compliance demonstration methods for various HAPs, including hydrogen fluoride. Section 3(f) specifies the testing schedule, and contains a reference to Section G(d)5, which prescribes the testing process. Per the permit, grab samples of coal are analyzed for HAP content, and to establish a correlation between HAP content and HAP emissions. After three years of correlation, the permittee may petition the Division to use the grab samples as a surrogate for compliance testing. However, unless and until that petition is made, the fluoride indicator value is not the approved compliance demonstration method, and therefore an exceedance of the fluoride indicator value is not a violation of the fluoride limit.*

Furthermore, the Draft Permit fails to require a methods for demonstrating continuous compliance with the VOC and SAM BACT limits for Unit 3. If the Permit will rely on CAM testing as the required monitoring for continuous compliance, the Permit must establish that a violation of the CAM parameters is a violation of the Permit limit. Additionally, while CO CEMS are required, the Draft Permit fails to require the use of CO CEMS to demonstrate compliance with the CO BACT limit.

**Division's Response:**

*Section B. 4., Case by Case MACT, for Emission Unit 08 (CFB 3) of the permit specifies that "The continuous compliance monitoring method used to assess compliance with the carbon monoxide emission limitation shall be used as indicator of good combustion practice. Compliance with the carbon monoxide emission limitation assures compliance with the VOC (VOC HAP) emission limit." The proposed permit has been changed so that SAM compliance is demonstrated by the correlation between SAM emissions and $SO_2$ CEM readings established during source testing. Lime injection rate and $SO_2$ CEM readings are the indicators of continuing SAM compliance.*

*CAM is Compliance Assurance Monitoring; it is not a compliance demonstration method. A violation of the CAM requirements is not per se a violation of a permit limit. It may, however, based on the steps the company takes to bring the CAM indicators back into the acceptable range, result in the Division requiring additional testing to demonstrate compliance with the permit limits.*

The CAM plan includes indicator monitoring for SAM. Draft Permit, p. 29. However, this CAM plan for SAM is deficient. First, it appears to rely on only limestone injection in the boiler, ignoring the downstream SDA and baghouse. SAM indicator values will be established based on the SAM outlet concentrations, which are affected by the SDA and baghouse. Monitoring only the limestone injection does not monitor all of the parameters necessary to ensure operation consistent with emissions measured at the stack. Second, any relationship established between SAM and limestone injection depends on the fuel being burned. Therefore, monitoring of limestone injection is only sufficient if the permit establishes a limit on fuels, based on the most recent stack test used to establish the relationship between limestone injection and emissions.

**Division's Response:**

*This comment contains a reference to a page in the draft permit that is in the section for Spurlock Unit 4, but the comment is supposedly about Unit 3. However, the Division believes that the content of the response to the previous comment addresses the issue.*

## IV. Spurlock Unit 4

### A. Top-Down BACT Requires Much Lower Limits Than the Draft Permit Requires

The Clean Air Act defines BACT as an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation… emitted or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through the application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3). Kentucky law includes a similar definition. 401 KAR 51:001, sec. 1(25). BACT requires a forward-looking analysis of what the facility can achieve in the future, based on what is presently known about the effectiveness of the best pollution control options. Newmont Nevada Energy Investment, Slip Op. at 16.

EPA regulations require the Division, as the PSD permitting authority, to perform and document an analysis to ensure that BACT limits are at least as stringent as federal BACT. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j). To implement the BACT permitting, EPA established a "top-down BACT analysis" process, which it outlined in the USEPA's New Source Review Workshop Manual (Draft October 1990) ("NSR Manual"). EPA's Environmental Appeals Board has adopted the use of the NSR Manual as controlling authority when deciding cases. See Masonite Corporation, 5 E.A.D. 558 (EAB 1994); Inter-Power of New York, Inc., 5 E.A.D. 135 (EAB 1994). The Division implements PSD permitting in Kentucky by applying the NSR Manual's process as the appropriate analysis for new source review determinations. The Environmental Appeals Board has held that, when a state permitting agency attaches importance to the NSR Manual, the Manual then serves as "an important reference point in assessing whether [the agency] has acted rationally in the context of a given permit." In re General Motors, Inc., 10 E.A.D. 360, 366 (EAB 2002) (discussing Michigan's reliance on the NSR Manual).

The top-down BACT analysis consists of five steps:

1. Identify all control technologies (including lowest achievable emission rate or LAER)
2. Eliminate technically infeasible options
3. Rank the remaining control technologies by control effectiveness
4. Evaluate the most effective control and document results
5. Select BACT

NSR Manual at Table B-1. The first step of this process requires all available control technologies to be identified before any are rejected as technically infeasible or due to cost or other factors. After all available control technologies are identified, the most stringent or top alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agree, that technical considerations, or energy, environmental, or economic impacts justify the rejection of the top alternative. NSR Manual at B.2. If the top alternative is rejected, the next most stringent option is selected as BACT unless the applicant demonstrates, similar to the top alternative, that technical, environmental, or economic considerations justify the rejection of the second option. NSR Manual at B.2.

Although the focus of a BACT analysis is mainly on the control technology or pollution prevention practices applicable to an applicant source, BACT actually refers to the numeric emission limit (i.e., pounds per Million Btu heat input) that corresponds with a specific, "best," control option (i.e., a selective catalytic reduction system). Three Mountain Power 10 E.A.D. 31, 54 (EAB 2001). Therefore, DAQ must determine the top pollutant control option and set the corresponding limit based on the maximum pollution reduction achievable by that control technology. BACT is an emission limit "based on the maximum degree of reduction... that is achievable…" 42 U.S.C. § 7479(3). In other words, even after selecting the top control technology, the Division must also ensure that the BACT emission limit is the lowest achievable emission rate for each pollutant based on the control potential of the top technology. The NSR Manual clearly requires the lowest possible emission rate to be selected as the BACT limit. NSR Manual at B.29. If the lowest emission rate is not set as BACT, "the rationale for this finding needs to be fully documented for the public record." NSR Manual at B.29. U.S. EPA has continuously stressed the importance of a rigorous BACT analysis process and complete record supporting the permitting agency's determinations.

The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record. A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.

In re Knauf Fiber Glass, GmbH, 8 E.A.D. 121, 131 (EAB 1999); see also NSR Manual at B.26-B.29; In re General Motors, Inc., 10 E.A.D. 360, 379 (EAB 2002); In re Steel Dynamics, Inc., 9 E.A.D. 165, 206-07 (EAB 2002); In re Masonite Corp., 5 E.A.D. 551, 564-69 (EAB 1994). Therefore, when establishing a BACT limit, DAQ must identify the most effective pollution control option, and must set BACT based on that option unless the applicant can demonstrate that the most effective pollution control option must be rejected based on energy, environmental, or economic impacts- which are unique to the specific facility. As EPA has repeatedly stated, the collateral "energy, environmental, or economic impacts" exception to the top-control option is narrow, to be used sparingly on unique circumstances at the source. NSR Manual at B.29.

> The [collateral impacts] clause [of the BACT definition] allows rejection of the most effective technology as BACT only in limited circumstances. The collateral impacts clause operates primarily as a safety valve whenever unusual circumstances specific to the facility make is appropriate to use less than the most effective technology. In re Kawaihae Cogeneration Project, 7 E.A.D. 107, 116-17 (EAB 1997) (emphasis original); see also In re World Color Press, Inc., 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific local impacts).

It is important to note that the purpose of the top-down BACT process employed by EPA and DAQ is to default to the best control option and maximum pollution control possible, unless the applicant can demonstrate that such option must be rejected. "The top-down approach places the burden of proof on the applicant to justify why the proposed source is unable to apply the best technology available." Citizens for Clean Air v. EPA, 959 F.2d 839, 845 (9th Cir. 1992), citing In re: Spokane Regional Waste-to-Energy Applicant, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9 (internal quotation marks omitted) (emphasis in original); see also In re: Inter-Power of New York, Inc. 5 E.A.D. 130, 135 (EAB 1994) ("Under the 'top-down' approach, permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); In re Pennsauken County, New Jersey Resource Recovery Facility, 2 E.A.D. 667 (Adm'r 1988), available at 1988 EPA App. LEXIS 27, 28 (Nov. 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available."). Therefore, if EKPC wishes to avoid using the best control option and achieving the best pollution control possible, it bears the burden of proof and the burden of persuasion.

If DAQ accepts any option, other than the top-ranked pollution control option, it must make the necessary findings to substantiate its decision and must set forth its basis in the record. Inter-Power of New York 5 E.A.D. 130, 135 (EAB 1994). Although the BACT selection process is demanding on the applicant and DAQ, its purpose is simple: "to promote the use of the best control technologies." General Motors at 378, citing Knauf, 8 EAD 121, 140 (EAB 1999). Rather than establishing a static emission limit for new sources, Congress chose to require an emission limit based on the "maximum degree of reduction … achievable for such source" at the time the source is constructed. 42 U.S.C. §§ 7475(a)(4) (new sources are subject to BACT), 7479(3) (BACT definition). The result is increasingly stringent limits as technology and experience improves the ability to reduce or capture pollutants.

EKPC's application submittals, especially its January 13, 2006 submittal, misstate certain requirements of the BACT process. Notably, EKPC misunderstands procedural and fact finding decisions of the EAB as though the decisions set forth interpretations of BACT. For example, EKPC cites the EPA's EAB decision In re Cardinal FG Co., PSD Appeal No. 04-04, Slip Op., for the propositions that "[t]echnically feasible options are those that have been demonstrated in practice," and that a "technology also must have been demonstrated successfully on full-scale operations for a sufficient time to be considered proven." EKPC Supplemental BACT Information p. 3 (January 13, 2006) (hereinafter "EKPC Jan. 2006 Submittal"). To the extent EKPC suggests that a technology must be demonstrated in practice, or demonstrated for a minimum period of time, to be considered "technically feasible" in a BACT analysis, EKPC misreads the Cardinal FG case.

The crux of the Cardinal FG holding relates to the burden of proof and burden of production required by the procedural rule before the EAB. The EAB upheld the Washington Department of Ecology's ("WDOE") BACT determination, not because BACT requires a "demonstrated technology," as EKPC implies, but because the petitioner did not produce any evidence to satisfy its burden to prove WDOE wrong. Cardinal FG, at pp. 11, 17-18, 20. EKPC clearly misses this distinction. EKPC also fails to understand that, unlike the standard of review of a petitioner's claim of error in cases before the EAB, EKPC bears the burden to prove why it cannot apply the best technology available. Citizens for Clean Air, 959 F.2d at 845; Spokane Regional Waste-to-Energy Applicant, PSD Appeal No. 88-12 at 9; Inter-Power of New York, 5 E.A.D. at 135; Pennsauken County, 1988 EPA App. LEXIS 28. For Spurlock 4, EKPC fails to make the necessary demonstration for a number of pollution control options. As addressed in detail below, EKPC relies upon speculation and unsupported assertions to reject higher-ranked pollution control options.

EKPC also unjustifiably limited its BACT analysis by giving "more weight to those facilities burning similar fuel in proposing BACT" for Spurlock 4. EKPC Jan. 2006 Submittal p. 2. By "similar fuel," EKPC apparently means the specific type and quality of coal. This truncated analysis is not supported by the definition of BACT, the legislative history of the Clean Air Act, or EPA guidance. Quite the contrary, it is well established that an applicant and permitting authority must determine whether lower pollution rates are achievable by switching to a cleaner fuel. EKPC cites only the Newmont Nevada EAB case in support of its decision to limit its BACT analysis to CFB units firing the same fuel. EKPC Jan. 2006 Submittal p. 2, citing In re Newmont Nevada Energy Investment, LLC, PSD Appeal No. 05-04 (EAB Dec. 21, 2005). However, EKPC ignores the fact that the Newmont case is inapposite because, as the EAB specifically pointed out, the petitioner in Newmont "does not take issue with the choice of coal type proposed for the Plant." Newmont Nevada Energy Investment, at p. 22. In other words, the EAB limited its review of the permitting agency's analysis related to the specific coal proposed by the applicant because the petitioner did not raise the issue of fuel choice, not because BACT allows a permitting agency to ignore cleaner fuels in a BACT analysis. Whether other fuels could have achieved lower emission rates was explicitly excluded from consideration in the Newmont case because the petitioner did not raised that issue. Newmont Nevada Energy Investment, at p. 22.

**Division's Response:**

*The Division acknowledges the comment, but does not concur.*

**B. The Division Must Consider IGCC as BACT**

A BACT analysis for a coal fired power plant must include consideration of Integrated Gasification Combined Cycle ("IGCC") technology. IGCC is an inherently cleaner production process for the generation of electricity from coal that prevents the emissions of regulated pollutants into the atmosphere by removing contaminants such as sulfur and mercury from the hydrocarbons in the coal before the hydrocarbons are burned. IGCC is an established technology that is already "available" for commercial power production applications and at competitive costs, and within the meaning of 42 U.S.C. §7479(3). See e.g., Gregory B. Foote, Considering Alternatives: The Case For Limiting CO2 Emissions From New Power Plants Through New Source Review, 34 ELR 10642, 10647 & n.54, 10659-60; see also Edward Lowe, General Manager, Gasification, GE Energy, GE's Gasification Developments, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October 10, 2005); Ron Herbanek, Mechanical Engineering Director, E-Gas and Thomas A. Lynch, Project Development Manager, ConocoPhillips, E-Gas Applications for sub-Bituminous Coal, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October, 11 2005). There are over 131 gasification projects operating worldwide, which include over 23,750 MW of energy production. Simbec, SFA Pacific, Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-19, 2002. Many of these units produce chemicals as well as power. Two full-scale commercial IGCC electric generating units are in operation in the United States: Cinergys 192 MW unit at Wabash River, Indiana, and Tampa Electric Co.'s 262 MW unit at Polk plant. See Resource Systems Group, In, EPIndex, available at www.epindex.com. IGCC units constructed with multiple gasifiers can achieve the same reliability levels as conventional baseload facilities. The Eastman Chemical plant in Kingsport, Tennessee utilizes dual gasifiers and experiences availability above 98 percent. Smith, Eastman Chemical Plant Kingsport Chemicals from Coal Operations, 1983-2000, 2000 Gasification Technologies Conference. ChevronTexaco, for example, provides an IGCC plant which achieves greater than 90% availability through the use of multiple gas trains. O'Keefe and Sturm, Clean Coal Technology Options- A Comparison of IGCC vs. Pulverized Coal Boilers, presented to the 2002 Gasification Technologies Conference, October 2002.

IGCC constitutes a fuel cleaning and an innovative fuel combustion technique under the definition of BACT. NOx emissions from an IGCC plant are lower than those for modern coal-fired plants. Additionally, because sulfur is removed from the syngas before combustion, SO2 emissions are less than half of that for a comparable traditionally-fired coal unit. Mercury and CO2 control is also much easier for an IGCC plant than PC or CFB plants. See The Cost of Mercury Removal in an IGCC Plant at 1-2, US DOE, NETL, Sept. 2002. The Wisconsin Department of Natural Resources issued a permit for an IGCC unit in 2004, which included limits significantly lower than those for other coal-fired generation processes. Id. Moreover, EPA recognizes IGCC as an 'inherently low-polluting process/practice' for generating electricity, as indicated in a presentation given by EPA representatives. See, e.g., Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Activities", Presentation to the Gasification Technologies Council Winter Meeting, January 26, 2006; "U.S. EPA's Clean Air Gasification Initiative," Presentation at the Platts IGCC Symposium, June 2, 2005. EPA also found, after significant investigation, that IGCC is an effective method for controlling SO2 emissions from the production of steam generated electricity.

This can be accomplished by burning… a fuel that has been pre-treated to remove sulfur from the fuel… There are two ways to pre-treat coal before combustion to lower sulfur emissions: Physical coal cleaning and gasification… Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO2 emissions by over 99 percent.

U.S. EPA, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 70 Fed. Reg. 9706, 9710-11 (February 28, 2005). Therefore, IGCC is BACT because it is a "clean fuel" option because it "will inherently have only trace SO2 emissions because over 99 percent of the sulfur associated with the coal is removed by the coal gasification process." Id. at 9715; In re Inter-Power of
New York, 5 E.A.D. 130, 134 (EAB, 1994) ("[i]n deciding what constitutes BACT, the Agency must consider both the cleanliness of the fuel and the use of add-on pollution controls."). IGCC is also a "innovative fuel combustion technique," within the definition of BACT. Congress explicitly recognized IGCC as a 'production

process and available method[], system[] and technique,' when enacting the BACT definition in 1977. The congressional history of the BACT definition includes the following discussion:

> Mr. HUDDLESTON. Mr. President, I send to the desk an unprinted amendment.
>
> The PRESIDING OFFICER. The amendment will be stated.
>
> The legislative clerk read as follows:
>
> The Senator from Kentucky (Mr. HUDDLESTON) proposes an unprinted amendment numbered 387: On page 18, line 15, after "ment" insert "or innovative fuel combustion techniques."
>
> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective controls.
>
> The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production process and available methods, systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of <u>BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain.</u>
>
> It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account- be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, <u>gasification</u>, or liquefication; <u>use of combustion systems such as fluidized bed combustion</u> which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers.
>
> The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation.
>
> Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
>
> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.

123 Cong. Rec. S9434-35 (June 10, 1977) (debate on P.L. 95-95) (emphasis added). In fact, the Division's counterparts in other states, including the state of Illinois, have concluded IGCC must be considered in the BACT analysis for a coal plant. <u>See</u> Letter from Renee Cipriano, Director, Illinois Environmental Protection Agency ("IEPA") to Thomas Skinner, Regional Administrator, Region V, EPA (March 19, 2003) (announcing IEPA's conclusion that "it is appropriate for applicants for [coal-

fired power] plants to consider IGCC as part of their BACT demonstrations."); see also Letter from IEPA to Indeck-Elwood LLC (March 8, 2003)(formally notifying the applicant of the need to supplement its proposal to address IGCC as part of the BACT demonstration). Moreover, the Division, itself, agrees that IGCC must be considered in a BACT analysis. In its February 9, 2005 letter to EKPC, the Division states:

…IGCC was excluded from consideration. Justification of why IGCC is not appropriate to consider under 401 KAR 51:017 or sound technical reasons for exclusion must be submitted. For instance, CITGO's Lake Charles gasification project is scheduled to begin commercial operation in the first quarter of 2005, the Lima Energy Facility, a 580-megawatt coal fired plant, is also not addressed.

Letter from Ben Markin, Combustion Section Supervisor, Division of Air Quality, to Robert Hughes, East Kentucky Power Cooperative at 2 (Feb. 9, 2005) (on file with Ky. DAQ).

Contrary to prevalent misconceptions, considering cleaner production processes- which is what IGCC is- does not "define" or "redefine" the source. Indeed, a CFB plant and an IGCC plant are the same source: both are processes for creating electricity from coal-fired steam generation. In 1998 EPA adopted a nitrogen oxide limit as part of its new source performance standards that applied to all new electric generating units, regardless of whether it uses pulverized coal or IGCC combustion technologies. Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units, 63 Fed. Reg. 49442 (September 16, 1998). On February 28, 2005 EPA proposed to revise its new source performance standards for the new electric generating units source category and, again, did not distinguish between pulverized coal and IGCC technologies. 70 Fed. Reg. 9706 (Feb. 28, 2005). In other words, EPA treats all electric generating units that burn coal (including gasified coal) as the same source category, and therefore as the same "source."

The "redefining the source" policy—which, incidentally, is a discretionary agency policy and not binding law-- does not excuse a permitting agency from considering lower-polluting alternative production processes that produce the same product. Two decisions by the EPA Administrator explain the limited nature of the "redefining the source" policy. In Pennsauken County, New Jersey, Resource Recovery Facility the petitioner asked the EPA Administrator to deny a PSD permit to a municipal waste combustor and, instead, require the county to dispose of its waste by co-firing it with coal in existing power plants. PSD Appeal No. 88-8 at 10 (Adm'r, Nov. 10, 1988). The petitioner in Pennsauken County asked the EPA to order the applicant to engage in a different type of activity: electricity generation, rather than waste disposal. Not surprisingly, the Administrator determined that it would not "redefine the source" from a waste combustor to a power plant.

Petitioner Filipczak's fundamental objections to the Pennsauken permit are not with the control technology, but rather, with the municipal waste combustor itself. He urges rejection of the combustor in favor of co-firing a mixture of 20% refuse derived fuel and 80% coal at existing power plants. These objections are beyond the scope of this proceeding and therefore are not reviewable under 40 C.F.R. 124.19, which restricts review to "conditions" in the permit. Permit conditions are imposed for the purpose of ensuring that the proposed source of pollutant emissions-- here, a municipal waste combustor-- uses emission control systems that represent BACT, thereby reducing the emissions to the maximum degree possible. These control systems, as stated in the definition of BACT, may require application of "production processes and available methods, systems, and techniques, including fuel cleaning as treatment or innovative fuel combustion techniques" to control the emissions. The permit conditions that define these systems are imposed on the source as the applicant has defined it… [T]he source itself is not a condition of the permit.

Pennsauken County at 10-11 (emphasis added). The Administrator subsequently reaffirmed the Pennsauken County decision and explained that "source," within the newly created "redefining the source" policy, refers to a source category.
In Pennsauken, the petitioner was urging EPA to reject the proposed source (a municipal waste combustor) in favor of using existing power plants to co-fire a mixture of 20% refuse derived fuel and 80% coal. In other words, the petitioner was seeking to substitute power plants (having as a fundamental purpose the generation of electricity) for a municipal waste combustor (having as a fundamental purpose the disposal of municipal waste)…

In re Hibbing Taconite Company, 2 E.A.D. at n. 12 (Adm'r 1989) (parentheticals original, emphasis added). Furthermore, after clarifying the "redefining the source" policy as only applying when requiring a cleaner production process would change in the "fundamental purpose," the Administrator specifically rejected the idea that requiring consideration of cleaner fuel constitutes "redefining the source" because the fundamental purpose, or source category, remains the same.

[O]ne argument that could be made is that the Region, by requiring the burning of natural gas to be an alternative to be considered in the BACT analysis [for a petroleum coke-fired plant], is seeking to "redefine the source." Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project… [The redefining the source] argument has no merit in this case.

EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice. Here, Hibbing will continue to manufacture the same product (i.e., taconite pellets) regardless of whether it burns natural gas or petroleum coke… The record here indicates that there are other taconite plants that burn natural gas, or a combination of natural gas and other fuels. Thus, it is reasonable for Hibbing to consider natural gas as an alternative in its BACT analysis.

Id. at 842-843 (parenthetical original, emphasis added). In fact, the Administrator further explained that the "redefining the source" policy did not allow the permitting agency to blindly accept the source design, or fuel, proposed by the applicant. Id. Therefore, from its inception, EPA's "redefining the source" policy has merely stood for the concept that EPA will not require an applicant to abandon its intended purpose for some other industrial venture.

It would be misapplying the EPA Administrator's policy to recreate the 'redefining the source policy' as the 'redesigning the source rule'-- allowing the permit applicant to hold the BACT analysis hostage based on its chosen fuel, design, and combustion technology. By applying the "redefining the source" policy correctly, as described by the Administrator in Pennsauken and Hibbing, IGCC and CFB are not different "sources" from a CFB boiler. All are within the same source category. As in Hibbing, the redefining the source policy "has no merit in this case" because "EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice." Hibbing at 842-43.

**Division's Response:**

*IGCC would result in a redefinition of the basic design of the project and is not required under a BACT analysis. While the Division has asked for a review of IGCC technology in recent permits, it is the Division's understanding of the BACT review process that a fundamental redefinition of the project to an IGCC process is not required.*

*In addition, Stephen D. Page, Director, Office of Air Quality Planning and Standards, recently addressed this issue in his letter on December 13, 2005. Director Page determined that U.S. EPA "would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit." While the Division is aware that this determination of U.S. EPA is being challenged, we find that letter is consistent with the Division's understanding of the Act and regulations.*

*In addition, the Page determination state that review of IGCC could be performed under Section 165(a)(2) of the Clean Air Act that states:*

*(2) the proposed permit has been subject to a review in accordance with this section, the required analysis has been conducted in accordance with regulations promulgated by the Administrator, and a public hearing has been held with opportunity for interested persons including representatives of the Administrator to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations;*

*The Division has considered Sierra Club's comments as suggesting an IGCC system as an alternative to the construction of a CFB. With consideration of the staged nature of the construction at Spurlock and available information on IGCC technology, the Division will not require the use of an IGCC design as an alternative to a CFB.*

### C. Visible Emissions (Opacity)

The permit contains an opacity limit of 20%, except that a maximum of twenty-seven percent for not more than 1 six-minute per hour. Draft Permit § B.2.c., page 25. This emissions limit is based on the NSPS standard in Kentucky's SIP, and not on BACT level control. See Draft Permit § B.2., page 25, citing 401 KAR 59:016, sec. 3(2). The Draft Permit is therefore deficient. The permit must contain a visible emission limit for regulated pollutants (i.e., PM and SAM)[6] that is based on the maximum degree of reduction achievable with the best pollution control option for Spurlock 4. 401 KAR 51:001, Section 1(25); 401 KAR 51:017, Section 8.

As a PSD permit, the preconstruction permit for Spurlock 4 must require BACT for all regulated pollutants. 401 KAR 51:017, Section 8. BACT is defined as an "emissions limitation, including a visible emission standard…" 401 KAR 51:001, Section 1(25); see also 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12). Although a

BACT limit for PM or SAM typically includes an emission rate limit (i.e., pounds per hour or pounds per million Btu heat input), a BACT limit must nevertheless also "includ[e] a visible emission standard." Id. Other recent coal plant permits include visible emission as part of the BACT limits for those facilities. For example, the Springerville facility in Arizona has a BACT limit of 15% opacity, and the Mid-America facility in Council Bluffs has an opacity limit of 5 percent. See Iowa DNR Permit No. 03-A-425-P, §10a (Permit available online at http://aq48.dnraq.state.ia.us:8080/psd/7801026/PSD_PN_02-258/03-A-425-P-Final.pdf, last visited October 28, 2005). The Wisconsin Department of Natural Resources set a 10% opacity limit as BACT for the Fort Howard (Fort James) Paper Company's 500 MW CFB boiler. See Ex. 4, p. 8. The Minnesota Pollution Control Board also considered the issue and determined that a 5% opacity limit should be established based on BACT. Ex. 9, pp. 15, 22, 26, 40. The maximum achievable visible emission reduction for a CFB boiler, however, is much lower than 5% opacity. For example, the JEA Northside CFB in Jacksonville, Florida, conducted a compliance test during the summer of 2002, while burning high-sulfur coal, and measured opacity of less than 2%. William Goodrich, et al., Summary of Air Emissions from the First Year Operation of JEA's Northside Generating Station, Presented at ICAC Forum '03, p. 16, attached hereto as Ex. 10. Testing done by Black & Veatch for the Department of Energy showed visible emissions at the JEA facility of 1.1 and 1.0% opacity. See Black & Veatch, Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Project, DOE Issue Rev. 1 p. 12 (Sept. 3, 2004), attached as Exhibit 11 hereto.

EKPC admits that a BACT limit requires a visible emission standard. See Permit Application p. 3-7 Table 3-2, 3-9 (Sept. 13, 2004) ("East Kentucky Power is proposing a BACT limit of 20% opacity…"). Nevertheless, EKPC argues that the Permit should not include a visible emission standard as part of the BACT limits for Unit 4 because "[o]pacity is not a discrete pollutant that can be measured as other pollutants." EKPC Jan. 2006 Submittal, p. 33. This is simply false. Opacity is commonly measured through continuous opacity monitoring systems. Indeed, opacity must be measured for each of the Spurlock units. See e.g., Draft Permit pp. 3, 7, 14, 27.

The visible emission limit in the permit, based on 410 KAR 59:016, is not sufficient. The permit must contain BACT limits that include a visible emission standard. A complete BACT limit for PM and SAM requires a visible emission limit of no more than 2% opacity based on the results of testing at the JEA Northside facility. See Goodrich, supra, p. 16.

**Division's Response:**

*The Division does not concur.*

*The actual regulatory citation for BACT comes from 401 KAR 51:001 Section 1(25)*

*(25) "Best available control technology" or "BACT" means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that:…*

*210) "Regulated NSR pollutant" means the following:*

*(a) A pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the U.S. EPA;*

*(b) A pollutant that is subject to any standard promulgated under 41 U.S.C. 7411;*

*(c) A pollutant that is subject to a standard promulgated under or established by 42 U.S.C. 7671 to 7671q; or*

*(d) A pollutant that otherwise is subject to regulation under 42 U.S.C. 7401 to 7671q, except that any hazardous air pollutant (HAP) listed in 42 U.S.C. 7412 or added to the list pursuant to 42 U.S.C. 7412(b)(2), which has not been delisted pursuant to 42 U.S.C. 7412(b)(3), is not a regulated NSR pollutant unless the listed HAP is also regulated as a constituent or precursor of a general pollutant listed under 42 U.S.C. 7408.*

*From 401 KAR 51:001*

*Section 1 (7) "Air pollutant" means air contaminant.*

*KRS 224.01-010 Definitions for chapter.*
*As used in this chapter unless the context clearly indicates otherwise:*
*(1) "Air contaminant" includes smoke, dust, soot, grime, carbon, or any other particulate matter, radioactive matter, noxious acids, fumes, gases, odor, vapor, or any combination thereof;*

*An agency may use opacity as an emission limitation. There is neither a federal requirement nor a state requirement to have an opacity limit other than that contained in the applicable regulations. For this to be the case, one would have to read that opacity were a regulated pollutant. Opacity may be an indicator of particulate matter, fumes, gases or vapor, but it is not an independent entity to be regulated. Opacity is the property for the absorption of light, an appropriate indicator for a variety of air pollution concerns, but not a regulated NSR pollutant. The regulated NSR pollutant $PM/PM_{10}$ will be monitored by PM CEMs. This will provide a continuous method for ensuring compliance with the particulate emissions standard.*

**D. Particulate Matter Limits for Spurlock 4**

**1. PM/PM10 BACT Limits**

The draft permit establishes two PM limits based on 401 KAR 59:016, sec. 3(1)(b) and 401 KAR 51:017:

1) filterable emissions not greater than 0.009 lb/mmBtu based on 30 day CEM; and

2) total PM not to exceed 0.012 lb/mmBtu based on a 3 hour performance test.

The PM limit also states that "compliance with the 0.009 lb/MMBtu (filterable) emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, section 3(1)(b). This is not BACT for the PM emissions from Spurlock 4. BACT is 0.0088 lb/MMBtu for total PM emissions. Pennsylvania issued a PSD permit in April 1995 to the Northampton Generating Company with a total PM10 limit of 0.0088 lb/MMBtu. See Ex. 7, pp. 13-14.[7] This facility burns anthracite culm in a 1,146 MMBtu/hr circulating fluidized bed boiler. Compliance testing in February 2001 reported total PM10 emissions of 0.0045 lb/MMBtu. The permit limit and the compliance tests for Northampton have been rejected by other permitting agencies in the past due to those agencies' confusion as to whether the 0.0088 lb/MMBtu Northampton permit limit includes condensible PM. The confusion appears to stem from the fact that the Northampton permit requires testing by "Method 5." USEPA Method 5 tests only for filterable particulate matter. However, the "Method 5" referred to in the Pennsylvania DEQ Permit for Northampton refers to Pennsylvania Method 5, which includes both front half and some condensable (backhalf) emissions (i.e., both filterable and condensible PM). See Ex. 8. The Pennsylvania permit and compliance tests for Northampton included condensible fraction PM in the backhalf of the control train. Id.

A test of the JEA facility, conducted by Black & Veatch for the Department of Energy, measured filterable PM emissions of 0.004 lb/MMBtu. See Ex. 11 (Black & Veatch, Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Project, DOE Issue Rev. 1 p. 12 (Sept. 3, 2004)). This is significantly lower than the proposed 0.009 lb/MMBtu filterable limit proposed in the Draft Permit. EKPC concedes that other permits have lower total PM limits. EKPC Jan. 2006 Submittal p. 24. As EKPC points out Greene, River Hill and Northampton permits contain lower total PM limits. Id. EKPC claims that it should be held to a lower standard due to "coal differences." If anything, EKPC should be held to a higher standard because the coal that EKPC proposes to burn in Spurlock 4 has lower ash content, and therefore will produce less PM, than the facilities with lower PM limits that burn lower ash coals. Moreover, EKPC tries to have it both ways, pointing to another facility with a higher PM limit, which also burns different coal than Spurlock 4, as representative of Spurlock 4. Id. (claiming AES Puerto Rico is representative of Spurlock 4 for PM, but not SO2).[8]

Furthermore, other permits establish limits for PM that include periods of startup and shutdown, which the Spurlock 4 permit PM limits do not. PM emissions can be much higher during startup and shutdown periods, so an averaging time for determining compliance with a permit limit that includes periods of startup and shutdown requires additional control during normal operating conditions and is therefore more restrictive.

**Division's Response:**

*The Division acknowledges the comment but does not concur.*

**2. A PM2.5 BACT Limit Is Required.**

The Draft Permit also fails to include a PM2.5 BACT limit. Kentucky's PSD program requires a BACT limit "for each regulated NSR pollutant for which the source has the potential to emit in significant amounts." 401 KAR 51:017, sec. 8(2). A "regulated NSR pollutant" includes any "pollutant for which a national ambient air quality standard has been promulgated…" and any other "pollutant that otherwise is subject to regulation under 42 U.S.C. 7401 to 7671q…." 401 KAR 51:001, sec. 1(210)(a), (d). The EPA established a "national ambient air quality standard" for PM2.5 in 1997, based upon this pollutant's association with a range of adverse health effects. 62 Fed. Reg. 38711; 40 C.F.R. § 50.7. Following industry's exhaustion of its last-ditch appeals, the NAAQS for PM2.5 was upheld. American Trucking Associations, Inc. v. EPA, 283 F.3d 355 (D.C. Cir. 2002). Therefore, PM2.5 is both a pollutant for which a NAAQS is established and a pollutant subject to regulation under the Clean Air Act, either of which makes PM2.5 a "regulated NSR pollutant" under 401 KAR 51:001, sec. 1(210). PM2.5 will be emitted from Spurlock 4 in a "significant" amount because it will be emitted at "any emission rate." 401 KAR 51:001, sec. 1(221)(b). The Draft Permit must be revised to include a BACT limit for PM 2.5 and re-noticed for public comment.

Contrary to EKPC's assertions, PM10 cannot be used as a surrogate for PM2.5. First, the 1997 memo does not and cannot bind states or the EPA as a matter of law. See Memorandum from Stephen Page, Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas, p. 4 ("The statements of [the 1997 Seitz memo] do not bind State and local governments and the public as a matter of law."). Moreover, EKPC's assertions that the PM2.5 NAAQS does not implement itself is irrelevant. 401 KAR 51:001, sec. 1(210), (221), and 401 KAR 51:017, sec. 8(2) implement PSD permitting, which requires a BACT limit for PM2.5.

**Division's Response:**

*The Division acknowledges the comment but does not concur. At this time, US EPA has not established implementation protocols nor have they promulgated reference test methods for the PM 2.5 standard. All EPA guidance and procedures involve using PM 10 as a surrogate for PM 2.5.*

3. **The PM/PM10 BACT Limit for the Cooling Process Is Deficient**.

The PM limit for the cooling towers is also not BACT. The Draft Permit establishes a limit that requires the cooling tower to "utilize 0.0005% Drift Eliminators." Draft Permit, p. 65. This is not BACT, and it is not an enforceable emission limit. First, the drift rate, by itself, does not correspond to PM emissions. PM is formed by dissolved solids in the circulating water. The drift is emitted from the towers, the water is evaporated, leaving the solids that become articulate matter. The percent of the circulating water that is emitted (drift rate), by itself, is not a measure of particulate emissions.

Second, an emission rate, calculated from the drift fraction, TDS, and circulating water flow rate should be established as the permit limit for the cooling tower, based on a top-down BACT analysis. The draft permit sets a drift rate and requires that TDS be measured, but it falls short as it does not set an emission rate, or require monitoring of the circulating water flow. Absent a limit on the dissolved solids in the circulating water, 0.0005% drift does not limit PM. If the Division relies on drift eliminators (on the cooling tower) to establish BACT, the Permit must include a limit on the dissolved solids and circulating water flow rate based on the lowest concentration achievable. The permit must also include monitoring of dissolved solids and an initial test and periodic of drift rates. However, because a cooling tower with drift eliminators is not the least polluting technology, it should not be used as the basis for BACT.[9]

Use of an air cooled condenser ("ACC"), an alternative method, system or technique of cooling within the definition of BACT, is available and has lower PM10 emissions than a cooling tower with drift eliminators. ACCs have been used on large coal-fired power plants for over 25 years. The 330 MW Wyodak coal-fired power plant in Wyoming has successfully operated with an ACC for over 25 years. The largest ACC-equipped coal fired power plant in the world, the 4,000 MW Matimba facility in South Africa, has been operating successfully for over 10 years. Two coal-fired units in Australia with condenser heat rejection rates nearly identical to that proposed for Weston Unit 4 have been operational since 2002. A number of new coal-fired power plants have been proposed in New Mexico over the last three years. In all cases the project proponents have voluntarily incorporated ACC into the plant design to minimize plant water use. A 36 MW pulverized coal unit in Iowa, Cedar Falls Utilities Streeter Station Unit 7, was retrofit with dry cooling in 1995 due to highway safety concerns caused by the wet tower plume in winter. The use of dry cooling on pulverized coal fired power plants is well established.

The application of an AAC would eliminate nearly all of the PM emissions from the cooling process. Therefore, unless AAC can be rejected in a top-down BACT analysis, based on site-specific collateral impacts, it must be used to establish BACT. AAC cannot be eliminated based on cost, especially because it must be compared to the total cost of a cooling tower, including the towers, raw water clarification system, and intake structures. Moreover, use of AAC has additional environmental benefits, including no water withdrawals for cooling, no brine discharge to river, no aesthetic issues related to visible vapor plumes, no cooling tower drift emissions or particulate deposition.

Other potential options to reduce PM/PM10 emissions from the cooling process include a plume abated tower and a wet/dry system. Like ACC, these alternative processes result in lower emissions and, therefore, must be considered in a top-down BACT analysis. EKPC's analysis fails to identify, much less consider these options for reducing PM/PM10 emissions. A revised BACT analysis must be conducted for the cooling process.

**Division's Response:**

*The Division acknlowledges the comment but does not concur. A cooling tower is an integral part of the design of the facility. Given that EKPC has chosen to build a facility employing a cooling tower as part of the process, a drift eliminator with a maximum drift rate of 0.0005%, as included in the permit, is BACT. This drift rate was suggested as BACT by the Sierra Club in comments on a recently permitted electric generating unit.*

**E. Carbon Monoxide Emission Limit for Spurlock 4.**

The Draft Permit establishes a CO limit of 0.1 lb/MMBtu. Draft Permit, p. 25. This is not BACT. BACT for a CFB boiler is 0.027 lb/MMBtu, based on emission testing of the JEA facility. See Ex. 11, p. 12. This represents the maximum degree of reduction achievable at a coal-fired CFB boiler.

**Division's Response:**

*The Division acknowledges the comment but does not concur. While emissions testing and operational data from other similar facilities is a consideration in determining BACT limits, it is not the only factor taken into account when determining a specific BACT limit. BACT at any given existing facility does not de facto establish what is the correct BACT limit at any other facility. Based on the application and analysis for Spurlock Unit 4, 0.1 lb/mmBTU is the appropriate BACT limit for CO.*

### F. SO2 Limits for Spurlock 4

The draft permit contains an SO2 emission limit for Unit 4 of 0.15 lb/MMBtu based on a twenty four (24) hour average. § B.2.d. This is based on 401 KAR 59:016, sec. 4(1) and 401 KAR 51:017. Additionally, the draft permit provides that compliance with this limit "shall constitute compliance with the thirty (30) day rolling average contained in 401 KAR 59:016." Id.

A limit of 0.15 lb/MMBtu does not represent BACT for a number of reasons. First, the BACT analysis fails to consider cost-effective lower sulfur coal as an SO2 control option. Second, other coal-fired CFB boilers have been permitted for and have achieved much lower emission rates than 0.15 lb/MMBtu. Third, the BACT emission limit must contain a control efficiency to ensure maximum control regardless of coal sulfur content. Fourth, the best available control technology for SO2 control is a jet bubbling reactor, which can achieve 99% control of SO2 from the boiler at Spurlock 4, is cost effective, and is technologically feasible.

#### 1. The Division Must Consider and Establish BACT for SO2 Based On Lower Sulfur Coal.

Sulfur dioxide emissions from power plants like Spurlock 4 originate as sulfur in the fuel coal. Some of the sulfur content in the coal is removed prior to the boiler, some is removed in the ash produced in the boiler, and some is converted into sulfur trioxide. However, most of the sulfur in the coal is transformed into SO2 in the boiler. As the sulfur content of the coal being fired decreases, so too do the emissions of SO2. Therefore, the place to start to reduce SO2 emissions from a coal-fired power plant is where SO2 originates: the sulfur in the coal. The BACT determination for Spurlock 4 failed to consider lower sulfur coal as a fuel source to reduce SO2 emissions. In fact, EKPC does the opposite-- and attempts to justify a higher SO2 limit than has been required at similar facilities, because Spurlock 4 will use high sulfur coal. See Permit Application pp. 3-8 to 3-9 (Sept. 13, 2004); EKPC Jan. 2006 Submittal, p. 21.[10] This is not a lawful exercise when establishing a BACT limit. Congress specifically defined BACT to require consideration of less-polluting fuels as a way to reduce emissions. 42 U.S.C. § 7479(3) (defining BACT as the "maximum degree of reduction achievable… through… clean fuels…"). The applicable Kentucky definition also requires consideration of less-polluting fuels. 401 KAR 51:001, § 1(25). If there were any doubts as to what Congress intended when it required a permitting agency to consider clean fuels when establishing BACT limits, EPA put them to rest:

The phrase 'clean fuels' was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add 'clean fuels' to the definition of BACT at the time the Act passed, 'as * * * codifying its present practice, which holds that clean fuels are an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls.' EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.

Inter-Power of New York, 5 E.A.D. at 134 (emphasis added, internal citations omitted); Knauf, 8 E.A.D. at 136; In re: Old Dominion Electric Cooperative, 3 E.A.D. at 794, n. 39 (EAB 1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."); Hibbing Taconite, 2 E.A.D. at 842-843 (remanding a permit because the permitting agency failed to consider burning natural gas as a viable pollution control strategy).

In fact, specific to Spurlock Unit 4, EPA has repeatedly commented that lower sulfur fuel must be used to establish BACT for Spurlock 4, or be rejected according to the "traditional top-down BACT procedures and selection criteria." See Letter from Donald I. Newell, DAQ, to Mike Binkley, EKPC p. 1 (Oct. 19, 2005) (requiring EKPC to provide a cost-per-ton-SO2 analysis due to EPA's determination "that fuel switching is an acceptable BACT alternative…"). The United States Court of Appeals for the Ninth Circuit similarly held, in Hawaiian Elec. Co., Inc. v. EPA, that low sulfur fuel could be selected as BACT for a facility proposing to burn high sulfur fuel. 723 F.2d 1440, 1442 (9th Cir. 1984).

According to EKPC's own analysis, using Powder River Basin coal, or low-sulfur eastern bituminous coal, would reduce SO2 emissions by 1,700 tons per year or more, and would be cost effective. EKPC Jan. 2006 Supp. pp. 7-8.[11] If Spurlock 4 burns high-sulfur coal (as it is proposing to do), it will release 2,208 tons of SO2 per year. Id. However, if Spurlock 4 burned eastern low-sulfur coal, it would release 302 tons of SO2 per year. Id. This switch is cost effective at $3,092/ton. Id. Permitting agencies typically consider any cost of less than $10,000 per ton to be cost effective for criteria pollutants. A thorough review of BACT determinations at power plants between 1979 and 1999 indicates that costs of SO2 control ranged to $7529/ton in 2002 dollars. Expert Report of Ranajit Sanhu, United States v. Ohio Edison, Case. No. C2-99-1181 (S.D. Ohio) pp. 33-34, attached as Exhibit 12, hereto. The South Coast Air Quality Management District established a $9000/ton threshold for SO2 BACT determinations in 1999 dollars. South Coast Air Quality Management District, Best Available Control Technology Guidelines Part A: Policy and Procedures (May 21, 1999), exhibit 13, hereto. This equates to $10,734/ton according to a simple inflation calculation by the Bureau of Labor Statistics. This threshold has been increasing in recent years and some agencies have found costs of $12,000 per ton to be cost effective. Notably, the California Bay Area Air Quality Management District issued guidelines for cost-effectiveness determinations for BACT, which establish a $18,300/ton threshold for SO2. Bay Area Air Quality

Management District, BACT/TBACT Workbook, Guidelines for Best Available Control Technology, p. 4, attached hereto as Exhibit 14.

Burning low-sulfur coal, at a cost of $3,092 per ton, is well below any threshold. Additionally, if Spurlock 4 burned PRB coal, it would emit 270 tons of SO2 per year (an 88% reduction from the facility as proposed). Id. This switch is also cost effective at $8,033/ton[12]. Id. Not surprisingly, because low sulfur coal is cost-effective and achieves much lower SO2 emission rates than EKPC proposes, EKPC tries to avoid the requirement to consider low-sulfur fuels altogether. First, EKPC asserts that using lower sulfur coal "would be inconsistent with the scope of the project." EKPC Jan. 2006 Supp. p. 5. EKPC is clearly trying to take advantage of EPA's policy of not "redefining the scope" of a facility through a BACT determination. See e.g., NSR Manual B.13. However, EKPC cannot make its fat-footed argument fit the tiny glass slipper that is the "redefining the source" exception to BACT. As noted above, "redefining the source" policy only prevents the permitting agency from requiring the applicant to build a different type or "fundamental scope" of facility- such as substituting a power plant for a municipal waste combustor. In re Hibbing Taconite Company, 2 E.A.D. at n. 12 (Adm'r 1989). In fact, EPA explicitly rejected the very argument EKPC is trying in this case. Id. at 842-43. The Administrator in Hibbing Taconite explained that:

Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project… [The redefining the source] argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice.

Id. (emphasis added). Moreover, the legislative history of the Clean Air Act intended to create a preference for lower polluting fuels. The 1990 Clean Air Act Amendments revised section 169(3) to expressly require "clean fuels" as a pollution control option that must be considered when determining BACT. Pub. L. No. 549 § 403(d), 104 Stat. 2399, 2631-32. EPA's contemporaneous interpretation of this amendment was that the "clean fuels" requirement in the definition of BACT codifies the policy "that clean fuels are an available means of reducing emissions to be considered along with other approaches in identifying BACT level controls." Letter from William Rosenberg, U.S. EPA Assistant Adm'r for Air and Radiation, to Henry A. Waxman, Chair, Subcommittee on Health and Environment (Oct. 17, 1990), reprinted in 136 Cong. Rec. at S16916-17. Moreover, in numerous cases since the 1990 Amendments, the EPA has consistently determined that cleaner fuels must be preferred in BACT determinations, subject only to being rejected based on site-specific unique energy, cost, and environmental reasons. See e.g., Inter-Power of New York, 5 E.A.D. at 134; Knauf, 8 E.A.D. at 136; In re: Old Dominion Electric Cooperative, 3 E.A.D. at 794, n. 39 (EAB 1992); Hibbing Taconite, 2 E.A.D. at 842-843. The 1990 amendments and EPA's decisions since 1990 negate any prior EPA policy statements that discouraged reliance on cleaner fuels.

Apparently recognizing that it cannot merely refuse to consider lower sulfur fuel, EKPC changed its story from not having to consider lower sulfur coal in its SO2 BACT analysis, to its claim that lower sulfur coal is not feasible at Spurlock 4. Specifically, EKPC argues, without citing any specific technical support, that burning lower sulfur coal would increase its NOx emissions above 0.1 lb/MMBtu.

Letter from Robert E. Hughes, Jr., EKPC, to Donald Newell, DAQ p. 9 (Nov. 9, 2005) (EKPC Response to Question 3). EKPC argues:

The Spur IV CFB is designed for high ash, high sulfur coal. The unit cannot burn lower sulfur, ash coals [sic], and maintain a NOx emission limit of less than 0.1 lbs/MMBtu. Fuel switching has been determined to be an acceptable BACT alternative. However, it is not possible to use fuel switching as BACT on the Spur IV unit.

Id.[13] EKPC is clearly trying hard to avoid what BACT requires—considering lower sulfur coal in the BACT analysis and only rejecting it if it is not a cost-effect (in dollars per ton of SO2 removed) control option. However, there are a number of legal and factual problems with EKPC's attempt to avoid consideration of low sulfur coal.

First, the factual opposite is true. Low sulfur coals, such as PRB coals, generally have lower fuel nitrogen concentrations and lower heat contents. The lower fuel nitrogen means the fuel nitrogen component of NOx is lower. The lower heat content means that the fuel burns at a lower temperature, producing less combustion NOx. These two factors combined would produce much lower NOx concentrations than burning a high sulfur coal. It is well known, for example, that PRB coals produce lower NOx concentrations than high sulfur bituminous coals.

Second, as demonstrated below, the NOx controls already proposed for Spurlock 4 will achieve less than 0.07 lb/MMBtu. Therefore, EKC is underestimating the control it will achieve with an SNCR. Moreover, as further demonstrated below, superior NOx control is achievable with an SCR. Therefore, even if EKPC were correct that it cannot burn low sulfur coal and achieve 0.1 lb/MMBtu NOx emissions with the control technology it is proposing, it could with an SCR.

Third, contrary to EKPC's unsupported assertions that it cannot be done, both the NEVCO Sevier CFB and the AES Puerto Rico CFB have permit limits of 0.1 lb/MMBtu for NOx and burn low sulfur fuel. See Exs. 5, 15, 16. Because existing permits require low sulfur coal and NOx emissions below 0.1 lb/MMBtu, it is assumed to be technically feasible. See NSR Manual at B.19. Furthermore, EKPC cannot hold the BACT analysis hostage by poorly designing its CFB to be unable to burn low sulfur coal. The fact that a facility must redesign its equipment to implement a control option does not make that option infeasible. NSR Manual at B.20 ("physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility.").

EKPC must demonstrate that the price of using lower-sulfur coal, in dollars-per-ton of SO2 removed, is not "cost effective," for lower sulfur coal to be rejected as the basis for BACT. NSR Manual at B.31. To demonstrate that lower sulfur coal is not "cost effective" requires EKPC to demonstrate that the cost-per-ton of SO2 removed/prevented is disproportionate to the cost per ton incurred by other sources controlling SO2. Id. at B.31-B.32.

[T]he applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations.

Id. Absent a showing that the cost is disproportionate, the Division must establish a BACT limit based upon the use of cleaner coal. 42 U.S.C. § 7479(3)(defining BACT as the "maximum degree of reduction achievable… through… clean fuels…"); 401 KAR 51:001, § 1(25). EKPC cannot demonstrate any basis for not using low-sulfur coal. The cost of using low sulfur eastern bituminous coal, or even PRB coal, is not disproportionate to the cost of control at other facilities implementing BACT. For example, the cost to control SO2 at the Weston Unit 4 facility being constructed in Wisconsin is over $3,500 per ton of SO2 removed. As a rule of thumb, agencies generally do not consider costs below $10,000.00 per ton to justify rejection of a control option based on cost effectiveness.

Moreover, EKPC, itself, actually plans to use low sulfur coal. See Permit Application p. 3-8 (Sept. 13, 2004) (EKPC "wishes to have the capability to fire both high and low-sulfur coal…"). Ironically, while asserting its plan to burn high sulfur coal as the reason it should not be required to achieve a lower SO2 limit, EKPC also asserts its plan to burn low-sulfur coal as a reason it should not be required to achieve a lower PM limit. Id. Moreover, Alstrom, the maker of Spurlock 3 (which is identical to Unit 4) notes that its CFBS are capable of burning a wide range of sulfur content coals. See (ATTACH) John J. Butler, et al., ALSTROM, CFB Technology: Can the Original Clean Coal Technology Compete? (attached as Ex. 17); Bruce W. Wilhelm, et al., ALSTROM, Circulating Fluidized Bed Technology: Design Innovations and Operating Results (attached as Exhibit 18). In fact, the ability of CFBs to burn a wide range of fuels is one of the selling points for CFB technology. Therefore, as a legal matter, EKPC cannot escape consideration of lower sulfur fuel by claiming that CFB technology cannot accommodate such fuel because other CFBs do and the Unit 4 boiler can be modified (if necessary) to accommodate low sulfur coal. Additionally, as a factual matter, EKPC cannot make such a claim because CFBs similar (if not identical) to the boiler planned for Unit 4 can accommodate low sulfur fuel. EKPC must either use low sulfur coal or demonstrate, based on site-specific effects or unusual circumstances, that low sulfur coal can be rejected in a top-down BACT analysis. EKPC has not done so (and cannot do so), so BACT must be established based on low sulfur coal.

**Division's Response:**

*The Division does not concur that a limit restricting the coal sulfur content is appropriate or necessary for this type of unit, nor is the Division aware of any other permits for this type of facility that contain a limit in the permit on the percentage of sulfur that the fuel can contain.*

**2. The BACT Limit for Spurlock 4 Must Assume Coal Washing**

In addition to considering lower sulfur coal, the BACT analysis for Spurlock 4 must consider coal washing. According to EKPC's own analysis, coal washing would reduce SO2 emissions at Spurlock 4 by 203 tons per year. EKPC Jan. 2006 Submittal. p. 8. At $423/ton of SO2 removed, coal washing is cost effective. Id. EKPC's arguments, that incremental cost effectiveness justifies rejection, are misplaced.[14] First, EKPC contends that an $11,706/ton incremental cost justifies rejecting coal washing. Id. However, EPA cautions that incremental cost effectiveness should only be used in "certain limited circumstances" to reject a top-ranked control option. NSR Manual at B.31-B.32. Relying on incremental cost effectiveness distorts the actual cost of control. Therefore, EPA requires that permitting agencies not give "undue focus [to] incremental cost effectiveness [that] can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." NSR Manual at B.45-B.46. This is such a case—the incremental cost of coal washing distorts the cost analysis since the cost of SO2 control through coal washing plus scrubbing is well within the "normal range" for BACT costs. Incremental cost-effectiveness is never used, alone, to eliminate a control option that is within the range of average cost-effectiveness. Moreover, it is wrong to use incremental cost-effectiveness to compare a combination of controls (washing plus scrubbing) to scrubbing alone. Instead, incremental cost effectiveness is only used in conjunction with average cost effectiveness, and even then, only to evaluate the difference between dominant control technologies, not to evaluate the difference between using multiple controls to meet an emission limit (i.e., coal washing and FGD). NSR Manual at B.41, B.43-B.44. EKPC misapplies incremental cost effectiveness and impermissibly rejects coal washing as a control option.

In this case, the "cost effectiveness, in terms of dollars per total ton removed" is $423/ton, which is "well within the normal range of acceptable BACT costs." See Id. at 45-46. Therefore, coal washing cannot be rejected based on cost. Moreover, it does not appear that EKPC correctly determined cost, and, if it had, coal washing would be even more cost-effective. The Cost Manual requires EKPC to, inter alia, consider the reduced cost to operate downstream pollution control equipment due to cleaner coal from coal washing. Lower capital and operating costs for the SCR, baghouse, and FGD result from washed coal. Coal ash disposal and boiler and pollution control equipment maintenance costs decrease, and peaking capacity and heat rating, and plant availability rating increase as the sulfur and ash content decreases through coal washing. See P.S. Phillips and R.M. Cole, Economic Penalties Attributable to Ash Content of Steam Coals, Mining Engineering, v. 32, 1980, pp. 297-302. Additionally, because less pollution reductions are required from add-on controls, EKPC may save capital cost by designing smaller control devices. Reducing SO2 emissions also reduces the need to buy SO2 credits, which presently cost more than $1,800.00 per ton.

Moreover, coal washing cannot be rejected based on environmental impacts. EKPC cites creation of slurry waste as an adverse environmental impact justifying rejection of coal washing. However, EKPC fails to demonstrate that this "impact" is unique to Spurlock 4. The "collateral impacts" provision of the BACT definition allows a top-ranked pollution control option to be rejected if a site-specific and unique environmental (or energy or economic) impact is sufficiently overwhelming. To reject a top-ranked control option due to environmental impacts requires the applicant to demonstrate, with quantified evidence in the record, that the environmental impacts at the permitted site are different than those at other facilities who implement the control option. NSR Manual at B.47; In re Kawaihae Cogeneration Project, 7 E.A.D. at 116-17 (emphasis original); In re Old Dominion Elec. Coop., 3 E.A.D. 779, 792 (Adm'r 1992)); In re Columbia Gulf Transmission Company, PSD Appeal No. 88-11 4-6, 2 E.A.D. 824, 826 (Adm'r June 21, 1989)). It bears repeating that the collateral impacts must be unusual to the permitted source.

> The collateral impacts clause is not to be used to reject a control option that has the same collateral impacts everywhere that it is used. Id.
>
> The determination that a control alternative to be [sic] inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously… In the absence of unusual circumstances, the presumption is that sources within the same source category are similar in nature, and that [they can bear the same] cost and other impacts.

NSR Manual at B.29; see also In re Masonite Corp., 5 E.A.D. 551, 564 (EAB 1994). Indeed, EKPC, itself, acknowledges that rejecting a control option based on adverse environmental impacts "should be made on a consideration of site-specific circumstances." EKPC Jan. 2006 Submittal p. 5. Additionally, the site specific impacts must be fully documented in the record. NSR Manual at B.26-B.29; In re Knauf Fiber Glass, GmbH, 8 E.A.D. at 131.

EKPC has not shown that any environmental impacts associated with coal washing are unique to Spurlock 4. EKPC fails to point out site-specific unique environmental impacts posed by coal washing. Instead, EKPC actually cites environmental impacts at other facilities that use coal washing, demonstrating that such "impacts" are common to all facilities that use coal washing. EKPC Jan. 2006 Supp. p. 9. This demonstrates, conclusively, that the environmental impacts EKPC claims justify rejecting coal washing are not site-specific and unique, and therefore, cannot justify rejecting coal washing. Furthermore, EPA explicitly rejects EKPC's position that waste generated from coal washing precludes its consideration for BACT:

> [T]he fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications.

NSR Manual at B.47. Therefore, EKPC not only fails to make the requisite showing to avoid consideration of cleaner washed coal as the basis for BACT, the arguments EKPC does make actually demonstrate the opposite: that coal washing cannot be rejected based on collateral impacts. The BACT analysis done to-date is deficient and must be redone. A complete BACT analysis would result in much lower SO2 limits.

**Division's Response:**

*The Division acknowledges the comment but does not concur. Coal washing is not uniformly effective in reducing sulfur on eastern coal. According to publicly available information at http://www.coaleducation.org, the sulfur content of Eastern Kentucky coal is not significantly reduced by coal washing.*

**3. Other Facilities Are Subject To, And Meet, Lower BACT Limits.**

The Division's Statement of Basis provides only the following "analysis" for SO2 BACT:

Increased SO2 removal using dry scrubbing with limestone injection on Emission Unit 17 will provide the necessary emission reductions. While the Division concurs with the applicant that a dry scrubber in conjunction with limestone injection is the appropriate technology for SO2 control on Emission Unit 17, the Division does not agree with EKPC's proposal of 0.18 lb/mmBtu as the achievable emission rate, and is setting the SO2 emission limitation at 0.15 lb/mmBtu heat input on a 24 hour block average.

SOB p. 24. The Statement of Basis does not acknowledge the existing coal-fired CFB units that are permitted for and are achieving lower emission rates than 0.15 lb/MMBtu, nor explain why Spurlock Unit 4 cannot achieve lower SO2 emission rates. This is important, since a top-down BACT analysis must assume that Spurlock 4 can achieve the same emission rates as other facilities. NSR Manual at B.24, B.29.

Numerous other coal fired CFB boilers have received BACT limits much lower than 0.15 lb/MMBtu. The AES Puerto Rico facility in Guayama, Puerto Rico, received a PSD permit for two coal-fired CFB boilers (~225 MW/each) that contains the following SO2 BACT limits applicable to each CFB:

- 9 ppmdv @ 9% oxygen;
- 0.022 lb/MMBtu; or
- 54.1 lb/hour, whichever is more stringent on a three hour basis.

Exs. 15, 16. This facility was tested in October 2002. Unit 1 achieved 0.00037 lb/MMBtu SO2 emissions. See Ex. 19. Unit 2 achieved 0.0013 lb/MMBtu SO2 emission. Id. It appears that EKPC included this facility in it application, but failed to identify it as the lowest permit limit. See Permit Application, p. 3-6, Table 3-2 (Sept. 13, 2004) ("Cogeneration Plant (AES-PRCP)"). This may be because EKPC did not list the facility's limit in the same format as the other limits in the table (lb/MMBtu). Id.

The NEVCO-Sevier facility received a PSD permit for a 270 MW coal-fired CFB boiler with a BACT limit for SO2 of 0.05 lb/MMBtu over 24 hours and 0.022 lb/MMBtu on a 30 day rolling average. Exs. 15, 16. These limits include periods of startup, shutdown and malfunction. Id.

Other coal-fired CFB facilities in California have also received BACT limits much lower than 0.15 lb/MMBtu for SO2.

- Pyropower Corp. received a SO2 limit of 0.039 lb/MMBtu for a 49.9 MW coal fired CFB in 1986. See Ex. 6.

- BMCP (Thomas Oil) received an SO2 limit of 0.039 lb/MMBtu (96% control) for a coal fired CFB in 1986. Id.

- Cogeneration National Corp. received an SO2 limit of 95% control for two coal fired CFB units in 1985. Id.

These emission limits have been established as BACT at other similar facilities. Therefore, it is assumed that this is BACT for Spurlock Unit 4. NSR Manual at B.24, B.29. Nothing in the permit record suggests any reason why Spurlock 4 cannot achieve at least 0.022 lb SO2/MMBtu on a 24 hour average, which is the limit for

AES Puerto Rico. In fact, nothing indicates why Spurlock 4 cannot achieve 0.0013 lb SO2/MMBtu, which AES Puerto Rico achieved in practice. Therefore, BACT for SO2 emissions from Spurlock 4 is 0.0013 lb/MMBtu, or lower.

Additionally, the JEA Northside facility in Florida conducted an emission test in summer, 2002, while firing high sulfur coal in its 300 MW CFB boilers, and achieved 0.0-0.04 lb/MMBtu SO2 emissions. See Williams, supra, pp. 1, 16. Northside uses a spray dry absorber (dry FGD). The design specifications required 85% removal of SO2 in the CFB, and another 89.5% SO2 removal in the dry FGD. Id. at 2-3. While this is not as low as the AES Puerto Rico emission rates, it is significantly lower than the limit contained in the Draft Permit. This further demonstrates that the Draft Permit's 0.15 lb/MMBtu limit is much too high to constitute BACT.

**Division's Response:**

*See the response to comments E. and F. 1. The facilities referenced in this comment do, in fact, have lower $SO_2$ limits than that of Spurlock Unit 4. However, their $SO_2$ emission limits are established given the type of fuel that they intend to burn. The 0.15 lb/mmBTU limit for Spurlock Unit 4 was established based on the same principle and the analysis contained in the application.*

**4. BACT Should Be Established Based on the Bubbling Jet Reactor or Magnesium Enhanced Lime Scrubber, Which Can Achieve 99% Control of the Emissions from the Boiler Outlet at Spurlock 4.**

As an initial matter, the control efficiency of the entire SO2 control train—including limestone injection to the CFB boiler and the scrubber—must be distinguished from control efficiency of the scrubber alone. It is important to note the distinction between a scrubber that achieves 98% control standing alone, and a pollution control train that includes limestone injection and a scrubber that achieves 98% control total. EKPC's submission to the Division confuse this distinction. Many wet scrubbers achieve 98% control through the use of the scrubber alone. EKPC erroneously assumes that this is comparable to the 98% control EKPC assumes from the limestone injection plus scrubber for Spurlock 4. EKPC Jan. 2006 Submittal, p. 19 (98% control from MEL [wet] scrubbing "corresponds to the removal efficiency that will be attained by EKP's proposed SO2 control technology for Unit 4."). This is an apples-to-oranges comparison.

To accurately compare alternative wet scrubbing options to the dry scrubber proposed by EKPC, the Division must determine the additional control achievable with each scrubber technology, assuming a 0.9 lb/MMBtu inlet to either type of scrubber based on limestone injection in the boiler. See EKPC Jan. 2006 Submittal, p. 20 (0.9 lb/MMBtu outlet from CFB with limestone injection, assuming 9 lb/MMBtu coal). EKPC's comparison, on page 20 of its January 2006 submittal, assumes only 80%[15] control from the scrubber. The correct comparison is between this level of control and the 98% control achievable with a wet scrubber. Because limestone injection plus wet scrubbing achieves much greater SO2 control than the control options relied upon by EKPC, the BACT determination must be reevaluated.

A wet FGD system achieves better SO2 control than the dry FGD system proposed for Spurlock 4. Specifically, the Chiyoda CT-121 WFGD process, which employs a unique absorber design, called a jet bubbling reactor or "JBR," achieves much lower SO2 emission rates than the dry FGD being proposed for Spurlock 4. The JBR combines conventional SO2 absorption, neutralization, sulfite oxidation, and gypsum crystallization in one reaction vessel. Black & Veatch, which is the United States distributor of this technology, prepared an analysis for Wisconsin Public Service Corporation's Weston Unit 4, comparing type of applicable SO2 controls. See Black & Veatch Corp., Wisconsin Public Service Weston Unit 4, Flue Gas Desulfurization System Analysis (April 1, 2003) (attached as Exhibit 20). Black & Veatch described the JBR system as follows:

This absorber module is unique in the FGD industry because the surface area required for absorption of SO2 from the flue gas is created by bubbling the flue gas through a pool of slurry rather than by recycling slurry through the flue gas as in the other absorber types… Flue gas is pre-cooled with makeup water and slurry prior to entering the JBR's inlet plenum. The inlet plenum is formed by upper and lower deck plates. The flue gas is directed through multiple, 6-inch diameter, sparger tube openings in the lower deck.

These tubes are submerged a few inches beneath the level of slurry in the integral reaction tank in the base of the JBR. The bubbling action of flue gas as it exits the sparger tubes and rises through the slurry promotes SO2 absorption. The gas then leaves the reaction tank area to the outlet plenum via gas risers that pass through both the lower and upper decks. An external horizontal gas flow mist eliminator removes residual mist carried over from the JBR.

The JBR has several advantages compared to the other absorber modules described previously. Because SO2 absorption is achieved by bubbling flue gas into the reaction tank, the JBR vessel is relatively compact compared to a conventional spray absorber. Gypsum crystals produced in the JBR have a relatively larger size distribution since there is less attrition due to circulation through slurry recycle spray pumps. Most importantly, the removal efficiency of small particulates (less than 10 µm) is substantially better in the JBR compare to conventional spray absorbers. This directly increases the removal of condensed SO3 from the system as compared to most other competing wet scrubber designs, which remove practically no SO3. As with any of the absorber types, the advantages of the JBR must be evaluated on a site-specific basis by comparing total annualized costs at the same guaranteed performance levels with those of competing system proposals.

Chiyoda has installed over 20 JBR FGD systems around the world treating flue gas from over 10,000 MWe of generating capacity. In the US a 110-MWe JBR FGD system was installed at Georgia Power Company's Plant Yates Unit 1 in 1992 as part of the US DOE CCT program. A JBR has been in operation at the University of Illinois on a 40-MWe facility since 1988. The largest North American installation is at Suncor, Inc. in Alberta, Canada. This unit handles flue gas from process boilers (350 MWe equivalent) and has been in operation since 1996.

Id. at 4-11 to 4-14. Unlike the generic wet FGDs EKPC described in its submissions, which are less efficient at low inlet concentrations, the bubbling jet reactor has a different design and is capable of achieving 99% or greater SO2 removal at over a wide range of inlet concentrations, including low inlet concentrations such as the proposed 0.9 lb $SO_2$/MMBtu at Unit 4.

The Chiyoda can achieve, and has been guaranteed by the manufacturer for, 99% control. It has consistently achieved over 99% control during long term operation at the Shinko-Kobe power plant in Japan. Commercial Experience of CT-121 FGD Plant for 700 MW Electric Power Plant (attached as Exhibit 21); see also http://www.bwe.dk/pdf/ref-11%20FGD.pdf. This technology, combined with low-sulfur coal, represents the top-ranked control option for Spurlock 4. However, EKPC failed to identify this combination and properly analyze it in the top-down BACT process. Therefore, the BACT analysis must be redone for SO2.

In addition to the Chiyoda system, magnesium enhanced lime (MEL) wet scrubber technology can achieve 99 percent reduction. These types of wet FGD technologies are applicable to Spurlock 4, and achieve much greater control of SO2. See Ex. 21; Lewis Benson, Kevin Smith, and Bob Roden, New Magnesium-Enhanced Lime FGD Process, Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003 (attached as Exhibit 22); Phil Rader, Jon Augeli, and Stefan Ahman, FGD Technologies Achieving SO2 Compliance at the Lowest Lifecycle Cost, CEPSI 2000, Power-Gen Latin America, November 11-13, 2003 (attached as Exhibit 23).

MEL scrubbers use a special type of lime that contains magnesium in addition to its calcitic component. Magnesium salts are more soluble than calcium salts, which makes the scrubbing liquid more alkaline. This results in a higher $SO_2$ removal efficiency for a significantly smaller absorber tower than for lime alone. This process has a number of benefits including lower liquid recirculation, smaller pumps, lower scrubber-gas-side pressure drop, lower energy requirements, higher availability, and lighter byproduct gypsum than the conventional lime WFGD process. Srivastava and Jozewicz 2001. MEL scrubbers are in use on 15,700 MW of generation and have achieved 99% $SO_2$ control on high sulfur coals at a liquid-to-gas ratio substantially lower than the conventional limestone process. Exs. 22, 23. The MEL vendor, Carmeuse, will guarantee 99% $SO_2$ removal on high sulfur coal, and Babcock Power and other contractors will wrap the guarantee. MEL has been used on the 300-MW Mitchell Unit 3, Pennsylvania, under a Consent Decree to resolve two civil complaints to compel the owner to comply with SIP-approved rules.[16] The MEL system started up in 1982 and has consistently demonstrated greater than 99% $SO_2$ control.

BACT is a limit based on the maximum degree of control achievable with the best control technology. 401 KAR 51:001, sec. 1(25). The SO2 BACT limit for Spurlock must be based on the maximum control achievable from a JBR or a MEL scrubber. The permit must be revised to include a limit based on 98-99% control of $SO_2$ at the outlet of the boiler. Assuming a boiler outlet of 0.9 lb SO2/MMBtu (as EKPC does), 98% control achieves a scrubber outlet of 0.018 lb/MMBtu. Achieving 99% control corresponds to a scrubber outlet of 0.009 lb/MMBtu. This level of control must be established as BACT for Spurlock 4.

In limited circumstances a top-ranked control option is not used to set a BACT limit if energy, environmental, or economic issues justify rejecting the top-ranked control for a less effective option. NSR Manual at B.26-B.29. JBR or MEL scrubbing cannot be rejected as BACT for Spurlock 4. As noted above, EPA has repeatedly interpreted the "collateral impacts clause" as only allowing the rejection of the top control option when impacts unique to the specific facility being permitted make the top control inappropriate at that specific site. "The CAA contemplates the use of a less effective control technology only when source-specific energy, environmental or economic impacts or other costs constrain a source from using a more effective technology." General Motors at 381 (emphasis added); see also In re World Color Press, Inc., 3 EAD 474, 479-81 (Adm'r 1990) (remanding PSD decision on basis that alleged negligible collateral impacts did not justify the rejection of more stringent technologies as BACT).

The determination that a control alternative to be [sic] inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously…. In the absence of unusual circumstances, the presumption is that sources within the same source category are similar in nature, and that [they can bear the same] cost and other impacts.

NSR Manual at B.29; In re Kawaihae Cogeneration Project, 7 E.A.D. 107, 116-17 (EAB 1997) (emphasis original); Masonite Corp., 5 E.A.D. at 564; In re World Color Press, Inc., 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific local impacts). Impacts that are common to a control device, or are generally experienced at other facilities using a wet scrubber, are not unique to the facility and cannot justify rejecting a top-ranked control option. NSR Manual p. B.47. There are no site-specific, unique collateral impacts associated with JBR or MEL scrubbing for Spurlock 4.

EKPC has the burden to demonstrate that it cannot use bubbling jet reactor or MEL control options due to unique collateral impacts. This requires documented evidence. NSR Manual at B.26-B.29; Knauf, 8 E.A.D. at 131 ("A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified."). The permitting record shows that EKPC did not provide the required documented evidence of unique adverse impacts at the Spurlock site from bubbling jet reactor or MEL scrubbing technologies. At best, EKPC asserts that there are generic
"environmental impacts associated with wet FGD." EKPC Jan. 2006 Submittal, p. 20. However, EKPC also concedes that these impacts are common to every facility using a wet FGD. EKPC points to no source-specific impacts for Spurlock 4 that would preclude using the more effective wet FGD technology.

Moreover, a wet scrubber has environmental benefits (not adverse impacts), compared to the dry scrubber proposed by EKPC. First, it controls more SO2 emissions. This additional control is even more pronounced on a short term basis because a dry scrubber typically must be taken off-line to replace the atomizers, resulting in uncontrolled SO2 emissions. This is not necessary for the JBR or MEL scrubbers. Second, the JBR and MEL scrubbers remove more acid gases than a dry FGD system. See e.g., Lewis B. Benson, Kevin J. Smith, and Robert A. Roden, Control of Sulfur Dioxide and Sulfur Trioxide Using Byproduct of a Magnesium-Enhanced Lime FGD System, ICAC Forum 03, Multi-Pollutant Emission Control Strategies, 2003 (attached as Ex. 24). Third, the wet FGD system will also capture more volatile selenium emissions and mercury than a dry FGD.

Therefore, the Draft Permit is deficient because it fails to contain an accurate

BACT limit for Spurlock 4 that is based on the top-ranked control option for control of SO2. The BACT analysis must be redone and a BACT limit set based upon the control achievable with a JBR or MEL wet scrubbing system, in addition to limestone injection into the CFB and use of low sulfur coal. Based on a boiler outlet of 0.9 lb/MMbtu (EKPC's estimate), 99% control achieved by wet scrubbing requires an SO2 emission limit of 0.009 lb/MMBtu. Tests on JEA Demonstration Project, for the U.S. Department of Energy, measured actual SO2 rates at the boiler outlet at 0.24 to 0.29 lb/MMBtu. See Ex. 11, p. 12. Assuming these more realistic boiler outlet rates and 98% control, the BACT limit should be 0.00058 lb/MMBtu.

**Division's Response:**

*The Division does not concur with the conclusions in this comment. While the limits proposed by Sierra Club are theoretically possible, they have not been demonstrated at this type of facility. The Division is not aware of any similar CFB that is using wet scrubber technology.*

**5. The PSD Permit Must Include A Control Efficiency For SO2.**

The Draft Permit fails to include a minimum SO2 removal requirement. When the pollutant content of a fuel source varies it is necessary to have a control efficiency limit as part of a BACT limit. This is because BACT is an emission limit based on the maximum degree of reduction from a control option (or combination of options). Meeting a static permit limit (like the 0.15 lb/MMBtu limit established in the Draft Permit) depends on the SO2 inlet, and the coal sulfur content. Therefore, while a scrubber may have to operate at maximum control (i.e., maximum degree of reduction) when the inlet concentrations to the scrubber are at the maximum theoretical concentrations, the operator can meet the limit with much lower efficiencies when the coal sulfur content (FGD inlet concentration) decreases. For example, Spurlock 4 may be required to remove 99% of SO2 if it burns high sulfur coal to achieve a 0.15 lb/MMBtu limit. However, if Spurlock 4 burns lower sulfur coal, it may only be required to achieve 70% control to meet the same 1.5 lb/MMBtu limit. To comply with the definition of BACT, the control must be operated to assure that the emission limit corresponds to the maximum degree of reduction that is achievable. The permit limit thus must ensure that the operator maximizes the control possible from the scrubber (i.e., by adding sufficient limestone to the recycled slurry) at all inlet concentrations, the permit must require a minimal control efficiency to ensure "maximum degree of reduction," which is required by BACT.[17]

EPA requires that a BACT limit include either an SO2 removal requirement (i.e., at least 98% control at all times), or establish different emission limits based on the various inlet concentrations to the scrubber. See Ex. 24, pp. 3-4. In response to a proposed BACT limit for the City Utilities of Springfield facility that failed to include a percent removal requirement, EPA stated:

We also understand an applicant[']s desire for a margin of compliance when setting BACT. But in this case, establishing SO2 BACT at 0.12 #SO2/mmBtu effectively allows City Utilities to operate the SDA at an efficiency of 79% when burning PRB coal with an average SO2 inlet concentration of 0.58 #SO2/mmBtu and 87% when burning PRB coal with an average SO2 inlet concentration of 0.93#SO2/mmBtu.

These SO2 inlet concentrations correspond to the average and worst case monthly average inlet concentrations for all NSPS Subpart D affected public power units in Region 7 between 1997 and 2002. Both percent reduction efficiencies fall well below the long-term design performance anticipated for the SDA [dry scrubber] as BACT. To compensate for potential under-performance of the SDA when burning lower sulfur PRB coals, we believe the final permit should condition City Utilities to achieve a 92% reduction, based on a 30-day rolling average, in addition to the appropriate BACT emission limit. To assure that the SDA is operated in a highly effective manner during all periods of operation, the permit should also require City Utilities to install, operate, maintain, and quality assure inlet SO2 CEMS, in addition to the required stack CEMS, to verify that performance across the SDA is achieved. Since these CEMS are already required by the NSPS Subpart Da, it should not be an imposition to include in the permit. We also concur that any additional need for compliance margin has been accounted for in the analysis for lowering SDA performance from 94 to 92%... and should not be lowered any further.

Id. (emphasis added). EPA's concerns apply equally in this case. The solution for Spurlock 4 is the same as EPA's solution for the City Utilities permit: establish a percent reduction requirement in the permit. Id. This is done in permits for other facilities. Nevada (See Ex. 26); Montana (Ex. 27, p. 2 ¶ 13) ("The control efficiency of the SO2 emission control equipment, as measured by the inlet SO2 CEMS… and the outlet SO2 CEMS, shall be maintained at a minimum of 90% based on a rolling 30-day average."); Illinois (Ex. 28, p. 16) (98 percent removal required at Prairie State). Here, EKPC relies on 98% control for permitting. If DAQ accepts EKPC's proposed pollution control options as the basis for BACT, it must include a permit limit requiring, and sufficient monitoring to ensure compliance with, 98% control.

Additionally, there must be short-term limits. There is no limit in the Draft Permit that caps emissions over any 3-hour period, which does not protect the NAAQS or increment. Moreover, because malfunction periods are exempt, it does not appear that the Draft Permit protects NAAQS or increment during "malfunction" periods. Furthermore, because the dry scrubber that is proposed for Unit 4 requires periodic change-outs of the atomizers, which results in uncontrolled emissions, the Draft Permit does not protect air quality because it does not limit emissions during these short term periods. The applicant must redo its BACT analysis to account for these short-term periods, and the Draft Permit must establish short-term limits that protect NAAQS and increment.

**Division's Response:**

*The Division acknowledges the comment but does not concur. Pursuant to 401 KAR 51:001, Section 1(25)(c), the definition of BACT is:*

*an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that:*

*(c) Is satisfied by a design, equipment, work practice, or operational standard or*

*combination of standards approved by the cabinet, if:*
*1. The cabinet determines technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible;*
*2. The standard establishes the emissions reduction achievable by implementation of the design, equipment, work practice or operation; and*
*3. The standard provides for compliance by means that achieve equivalent results.*
*The emission limits for $SO_2$ contained in the permit meet the requirements of this definition without the addition of an additional limit on control efficiency.*

### G. The NOx Limits in the Draft Permit are not BACT.

The Draft Permit establishes a limit on NOx emissions for Unit 4 of 0.07 lb/MMBtu, based on a 30 day rolling average. Draft Permit § B.2.g., page 25. The Draft Permit also provides that: "The NOx emission limit is waived for the specific SNCR optimization study activity as detailed in Section D (6 and 7). Should the optimization study indicate that 0.07 lbs/mmBtu is unachievable, then a significant revision to the permit will be required. Under no case will the revised limit be greater than 0.09 lbs/mmBtu." Id. This does not represent BACT for two reasons. 1) 0.07 lb/MMBtu (nor the 0.09 lb/MMBtu "backstop") is not BACT because other similar units are already achieving lower NOx emission rates with the same controls as those proposed for Unit 4; and 2) BACT must be established based on the control achievable with an SCR, rather than an SNCR.

### 1. Existing Coal Fired CFB Units Have Lower NOx BACT Limits

Existing coal-fired CFB units have NOx permit limits lower than the 0.07 lb/MBtu limit proposed for Spurlock Unit 4. The BMC (Thomas Oil) facility has a NOx limit of 0.039 lb/MMBtu for its coal-fired CFB boiler. See Ex. 6. This represents 80% control of NOx from that facility. Id. Similarly, the Cogeneration National Corporation facility operates two coal-fired CFB boilers in California that have NOx emission limits of 30 ppmvd (3% oxygen). Id. This corresponds to 0.036 lb/MMBtu[18]. Additionally, the Corn Products facility in California also has a permit limit of 30 ppm (3% oxygen). Id. The Corn Products facility is also a coal-fired CFB boiler. Id. A top-down BACT analysis must assume that Unit 4 can achieve this same level of control. NSR Manual B.24, B.29.

Furthermore, a top-down BACT analysis must assume that Unit 4 can achieve 0.033 lb/MMBtu, based on NOx limits applicable in other states. A BACT analysis must include a consideration of LAER. NSR Manual at B.5-B.6. Unless the LAER level of control can be rejected as not technically feasible, not cost effective, or due to unusual collateral impacts at the permitted site, LAER must be established as BACT. NSR Manual at B.26, 53 ("If the applicant is unable to provide to the permit agency's satisfaction an adequate demonstration for one or more control alternatives, the permit agency should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided."). LAER for NOx control from Spurlock Unit 4 is, at least as low as 0.033 lb/MMBtu over a 24-hour averaging period, which is required by the Dallas-Forth Worth State Implementation Plan for coal-fired boilers. See Texas Register- Adopted Rules, Utility Electric Generation in Ozone Nonattainment

Areas, October 12, 2001, 26 Tex. Reg. 8159 (Houston-Galveston SIP requires 0.04 lb/MMBtu of NOx from coal fired plants.). Therefore, the 0.033 lb/MMBtu emission rate must be assumed to be BACT for Unit 4. This is lower than the 0.04 lb/MMBtu emission rate already required from coal-fired CFB boilers in California and in the Houston-Galveston area in Texas.[19]

EPA reports that uncontrolled NOx emission rates from a coal-fired CFB rages from 0.12 to 0.16 lb/MMBtu. See EPA 600/R-05/034. SNCR technology is capable of over 75% reduction of NOx emissions. Institute of Clean Air Companies-NOx Control Technology. http://www.icac.com/i4a/pages/index.cfm?papgeid=3399. CFBs are more conducive to this upper-end of SNCR control because the constant temperature and ability of the operator to control the heat to within a few degrees is ideal for operation of an SNCR. Moreover, because the reduction reagent is injected at the inlet to the hot cyclone, where flue gas is quickly swirled, the reagent and flue gas are thoroughly mixed. Assuming a mid-range average inlet concentration of 0.14 lb/MMBtu and 75% control from the SNCR, a CFB/SNCR can achieve NOx emissions under 0.04 lb/MMBtu. By optimizing combustion to keep boiler outlet rates to 0.12 and achieving 75% control with the SNCR, Spurlock 4 can achieve NOx emissions of 0.03 lb/MMBtu.

NOx emission rates of 0.04 lb/MMBtu and lower are achievable with state-of-the-art SNCR, high dust SCR, or tail-end SCR. EPA 600/R-05/034, Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, March, 2005. In fact, the Division told EKPC more than a year ago that "U.S. EPA has also approved/permitted BACT for NOx at Longview, West Virginia at the level of 0.04 lbs MMBtu." Letter from Ben Markin to Robert Hughes page 2, February 9, 2005. For each of these reasons, BACT is at least as low as 0.04 lb/MMBtu on a 24 hour basis if an SNCR is assumed to be the best control option for Unit 4. However, as described below, BACT is actually 0.02 lb/MMBtu, based on the use of an SCR.

**2. Existing Coal Fired CFB Units Are Currently Achieving NOx Emission Rates Below 0.07 lb/MMBtu**

In addition to the CFB units with NOx limits lower than those established in the Draft Permit for Spurlock 4, a number of coal fired CFB Units Are Achieving lower NOx emission rates than 0.07 lb/MMBtu, including periods of startup and shutdown, including those in the following table. Because these similar units already achieve a lower NOx emission rate—0.043 lb/MMBtu and lower—BACT is assumed to be at least as low as 0.043 lb/MMBtu.

**2003 NOx Operating Experience At Coal Fired CFB Boilers, Based on CEMS Data**

| FACILITY NAME | STATE | UNITID | NOX CONTROL INFO | CAPACITY INPUT | SUM OP TIME | NOX RATE | HEAT INPUT |
|---|---|---|---|---|---|---|---|
| Gilberton Power Company | PA | 31 | Overfire Air | 520 | 8,521 | 0.043 | 4,251,549 |
| Gilberton Power Company | PA | 32 | Overfire Air | 520 | 8,521 | 0.043 | 4,196,315 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Kimberly-Clark Tissue Company | PA | 35 | | 799 | 8,256 | 0.05 | 6,524,392 |
| Northeastern Power Company | PA | 31 | Other | 750 | 8,377 | 0.056 | 5,420,251 |
| AES Thames | CT | UNITA | Other | 1045 | 8,502 | 0.057 | 7,771,538 |
| AES Thames | CT | UNITB | Other | 1045 | 8,344 | 0.058 | 7,587,645 |
| Northside | FL | 2A | Selective Non-catalytic Reduction | 2672 | 7,079 | 0.062 | 17,570,074 |
| Northside | FL | 1A | Selective Non-catalytic Reduction | 2672 | 7,058 | 0.066 | 15,411,354 |

Additionally, the U.S. EPA reviewed a number of coal fired units in setting NSPS standards in 1997. U.S. EPA, Office of Air Quality Planning and Standards, New Source Performance Standards Subpart Da- Technical Support for Proposed Revisions to NOx Standard, EPA-453/R-94-012 (attached as Exhibit 29). U.S. EPA concluded that "NOx emissions from the circulating fluidized bed boilers ranged from 0.03 lb/MMBtu to 0.1 lb/MMBtu at full-load conditions." Id. at § 3.6.1.2, page 3-160. Three CFB units were meeting 0.03 lb/MMBtu. Id. All of these units were NH3 based SNCR systems. Id. The Energy Systems, Stockton Cogeneration facility burned bituminous coal and achieved 0.03 lb/MMBtu NOx emissions, representing 88.3% control. Id. at Table 3-36. Similarly, the JEA Northside facility was tested in 2002 while firing coal. The test showed Northside to be achieving 0.04-0.06 lb/MMBtu NOx while firing high-sulfur coal. Goodrich, supra, p. 16.

EKPC may attempt to argue that the annual operating data for the facilities above is insufficient to demonstrate that the emission rates are achievable. However, it should be noted that EPA developed the New Source Performance Standards for NOx, for the entire electric generation industry, based on only 90 days of NOx CEMs data. U.S. EPA, New Source Performance Standards, Subpart Da- Technical Support for Proposed Revisions to NOx Standard, p.3-177 (Ex. 29). Moreover, facilities typically control to a rate just under their permit limits. Any additional control is unnecessary and an added operating cost. This is demonstrated by the fact that Northside achieved 0.04 lb/MMBtu during a stack test, but operated its controls over the long term to merely stay within its permit limit. Therefore, the units above are likely capable of much lower NOx emission rates by operating their controls to achieve greater reductions.

The actual operating experience at a number of CFB units demonstrates that SNCR technology, when pushed to operate at maximum efficiency, can achieve NOx emissions well below 0.07 lb/MMBtu. Conversely, there is no justification for allowing EKPC to increase its limit to 0.09 lb/MMBtu, as the Draft Permit proposes.

**3. An SCR is an Applicable, Cost-Effective, Transfer Technology That Represents the Best Available Pollution Control Technology for Spurlock 4.**

While BACT must be 0.04 lb/MMBtu, or lower, based on the existing experience at coal fired CFB boilers using SNCR technology, BACT is actually much lower. The Division has requested EKPC to consider the use of an SCR at Spurlock 4 and Hitachi America has confirmed that they installed an SCR on one CFB in Sweden and another in Holland. However, EKPC submitted information to DAQ attempting to show that an SCR is not cost effective. EKPC Jan. 2006 Submittal pp. 11-14.[20] EKPC's "analysis" of an SCR is flawed for a number of reasons. These reasons are discussed below.

First, it appears that EKPC's "analysis" of an SCR assumes an SCR sized for a PC boiler. Because a CFB facility like Spurlock 4 has a much lower NOx loading rate to an SCR, the size and cost of an SCR for a CFB unit is significantly smaller than for a PC unit. D. Borio, Alstrom Power, R. Babb, TVA, <u>Technical and Economic Considerations in Hot or Cold Placement of SCR Systems for Utility Boilers</u>, ICAC Forum 2002. A more realistically sized SCR would result in a much lower cost, and therefore a cost-effective determination for an SCR for this facility. See e.g., EPA 2003, Air Pollution Control Technology Fact Sheet- SCR, EPA-452/F-03-032, p. 2; NSR Manual at B.36.

Second, the largest cost of using a cold-side SCR is the cost of natural gas to reheat the flue gas to the optimal temperature for an SCR (550 to 840 degrees F). EKPC incorrectly assumes that the flue gas must be reheated to the higher end of this range. EKPC Jan. 2006 Submittal p. 11. This, too, overestimates the cost of control for an SCR, which makes an SCR seem less cost-effective. Additionally, EKPC underestimates the amount of NOx that can be controlled with an SCR, which also results in overestimating the cost-per-ton of NOx removed. Instead of assuming the 90+% control achievable with an SCR, EKPC's cost estimate assumes the lowest possible emission control. EKPC Jan. 2006 Submittal p. 11 ("the removal efficiency can only be estimated to be at the lower end of the 60 to 90 percent range…"). This contradicts the NSR Manual, which requires that an applicant assume "the most recent regulatory decision and performance data for identifying the emissions performance level to be evaluated in all cases." <u>NSR Manual</u> at B.23. The most recent regulatory decisions conclude that SCRs are cable of 90+% control of NOx. EPA requires that "when reviewing a control technology with a wide range of emissions performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do other wise." <u>NSR Manual</u> at B.24.

Third, EKPC asserts that there is no experience with an SCR on a CFB unit in the United States. It is unnecessary for BACT purposes that an SCR has not yet be used on a CFB in the United States, especially since it has been used in other countries. Moreover, even if it has not been used on a CFB boiler, an SCR has been used on coal fired boilers in the United States. Transfer technologies-- from one type of source to another-- must be considered in a top-down BACT determination. <u>NSR</u>

Manual at B.11.

EKPC's claims are also misplaced because they put artificial constraints on the BACT analysis. It is not the type of boiler connected to the SCR that matters, as EKPC claims, but the characteristics of the flue gas entering the SCR. "Add-on controls… should be considered based on the physical and chemical characteristics of the pollutant bearing stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit under going BACT review." NSR Manual at B.10-B.11; Sur Contra La Contaminacion v. EPA, 202 F.3d 443, 448 (1st Cir. 2000) (upholding permitting agency's PSD permit based on control technologies that had never been used in combination before). Therefore, if an SCR can be designed to accommodate the flue gas characteristics of a CFB boiler, or if the design modifications to the boiler can correct for adverse characteristics, an SCR must be considered as a demonstrated transfer technology. NSR Manual at B.20. By correctly designing the SCR, 80-90% control is achievable at Spurlock 4. Using a control efficiency in the upper end of the SCR range (i.e., 80-90%) dramatically increases the cost-effectiveness of the SCR.

If the particulate matter from the CFB would cause a problem with traditional SCR units, two options are available: 1) installing a tail-end SCR after the baghouse; or 2) designing a control train and SCR that can accommodate higher ash concentrations. These must be considered in a BACT analysis. NSR Manual at B.20 ("Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility.").

A tail-end SCR (after the fabric filter) can eliminate the concerns about flue gas ash contamination of the SCR. Tail-end SCRs are capable of achieving 0.02 lb/MMBtu emission rates at Spurlock Unit 4. Tail-end SCR operation, however, requires reheating the flue gas to 550 degrees F. This can be accomplished by a gas-to-gas air heater. Some, but not much, supplemental natural gas may be required. However, not nearly as much natural gas would be required as EKPC assumes in its cost analysis. See EKPC Jan. 2006 Submittal, p. 11 (assuming reheat to 700-750 degrees F, rather than 550 degrees). Additionally, because the tail-end SCR would achieve much lower emissions than the 0.067 lb/MMBtu EKPC assumed, the cost-per-ton is much lower than EKPC estimates. See EKPC Jan. 2006 Submittal, p. 12 (assuming SCR outlet of 0.067 lb/MMBtu, rather than 0.02- 0.04 lb/MMBtu). EKPC assumed only 73.2% reduction with an SCR, while the tail-end SCR currently in use at the SPEG Mercer Units 1&2 is designed to achieve 90% NOx reduction. Tail end SCRs have been in use at other facilities for years. Overseas, many tail-end SCRs have been operating for decades. NJDEP, NOx Budget Hearing Transcript, Oct. 17, 1997, p. 58; EPA OAR, Performance of Selective Catalytic Reduction on Coal-Fired Steam Generation Units, Final Report, June 25, 1997. They are being planned for other units in the United States, including a retrofit on Salem Harbor Units 1, 2 and 3. See USGenNE, Petition for Zoning Exemption before Mass. Dept. of Telecomm. and Energy, Aug 23, 2003 at p. 2.

Alternatively, an SCR can be designed for the flue gas conditions of a CFB unit. An SCR designed for high-dust conditions would require a more open cell structure SCR, which is easily done by an SCR vendor. SCR manufacturers have also developed catalyst masking to deal with the high alkaline dust concentrations. S.

Pritchard et al., Optimizing SCR Catalyst Design and Performance for Coal-Fired Boilers, EPA/EPRI 1995 Joint Symposium Stationary Combustion NOx Control, May 1995. Furthermore, even if an SCR could not be designed to handle the ash concentrations from the CFB, there are a number of methods to reduce PM at the boiler exit, before a hot-side SCR. These include a more efficient cyclone, the use of a hot-side ESP, the use of a venturi scrubber or a ceramic tube filter. The latter option, installing a ceramic tube filter, is already being used on CFB units in Japan. See Hot Gas Particulate Cleaning T Technology Applied for PFBC/IGFC Technology- The Ceramic Tube Filter (CTF) and Metal Filter. In fact, the ceramic tube filter is in use on a coal-fired CFB with an SCR. Id. Because it is already used, it is assumed that this technology can be used at Spurlock 4. NSR Manual at B.29; see also Steel Dynamics, 9 E.A.D. at 202; Letter from Robert B. Miller, Chief Permits and Grants Section, USEPA, to Lynn Fiedler, Supervisor Permit Section, Michigan Department of Environmental Quality at 3 (October 6, 1999) ("where controls have been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the controls on those sources and the particular source under review"); In re Genesee Power Station, 4 E.A.D. at 868 (EAB 1993). Moreover, SCR systems have performed well at high ash levels, including on PC boilers with alkaline, high ash loadings.

EKPC's allegations about adverse environmental impacts are also misplaced. EKPC points to general allegations about emissions of ammonia and storage of ammonia, as well as replacement and disposal of SCR catalysts. EKPC Jan. 2006 Submittal, p. 14. These concerns were not quantified, as required. NSR Manual at p. 51. Moreover, it is important because the SNCR technology that is proposed for Spurlock 4 uses more ammonia, results in more ammonia emissions, and requires more on-site storage of ammonia. Unless the impacts from ammonia are quantified for both SCR and SNCR, it is inappropriate to use ammonia-related environmental impacts to prefer one technology over the other. As to SCR catalyst, they can be regenerated in place or regenerated offsite and are typically disposed by the vendor. We are aware of no issues with SCR catalyst disposal.

Additionally, EKPC fails to make the required showing that the impacts of ammonia and catalyst at Spurlock 4 would be different than at the many other facilities using an SCR. Kawaihae Cogen. 7 E.A.D. at 116-17; General Motors at 381; In re World Color Press, Inc., 3 EAD at 479-81. U.S. EPA rejects attempts, like EKPC's, to avoid use of the top control option based on environmental concerns that are common to the industry, rather than "unusual or unique" to the facility. In re Foster Wheeler Passaic, Inc., PSD Appeal No. 89-1, 1989 PSD LEXIS 18 (Adm'r 1989). Moreover, EPA explicitly rejects the very argument EKPC makes:

In limited other instances, though, control of regulated pollutant emissions may compete with control of toxic compounds, as in the case of certain selective catalytic reduction (SCR) NOx control technologies. The SCR technology itself results in emissions of ammonia, which increase, generally speaking, with increasing levels of NOx control. It is the intent of the toxic screening in the BACT procedure to identify and quantify this type of toxic effect. Generally, toxic effects of this type will not necessarily be overriding concerns and will likely not to [sic] affect BACT decisions.

NSR Manual p. B.52.

**Division's Response:**

*The Division acknowledges the comment but does not concur. While emissions testing and operational data from other similar facilities is a consideration in determining BACT limits, it is not the only factor taken into account when determining a specific BACT limit. BACT at any given existing facility does not de facto establish what is the correct BACT limit at any other facility. Based on the application and analysis for Spurlock Unit 4, 0.07 lb/mmBTU is the appropriate BACT for NOx for this facility. Further, the Division is unaware of any similar, coal burning CFB facility where an SCR has been required as BACT for NOx control.*

**H. Sulfur Acid Mist Emissions From Unit 4**

The Draft Permit establishes a limit on sulfuric acid mist (SAM) of 0.005 lb/MMBtu. This is not BACT for SAM emissions from Unit 4. The AES Puerto Rico permit established a SAM emission limit from a similarly sized CFB boiler to Unit 4 of 0.0024 lb/MMBtu. Ex. 5. The PSD permit for the NEVCO Sevier CFB boiler also established a 0.0024 lb/MMBtu SAM limit. Exs. 15, 16. Because this emission limit was established for a similar sized CFB unit, it is technologically feasible, and assumed to be cost effective and BACT for Spurlock 4. The Division must establish a BACT limit of at least as low as 0.0024 lb/MMBtu for Spurlock 4. Additional SAM control is achievable by using a wet electrostatic precipitator ("WESP") at the end of the pollution control train. A WESP can achieve SAM removal over 90% and limits as low as 0.0015 lb/MMBtu. Richard C. Staehle and others, The Past, Present and Future of Wet Electrostatic Precipitators in Power Plant Applications, Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003 (attached as Exhibit 30). A WESP has the added benefit of controlling additional PM10, PM2.5, mercury, other acid gases, and other HAPs.

Cleaner fuels (i.e., low sulfur coal) will also reduce SAM emissions. Generally, SAM emissions are reduced proportionate to the reduction in SO2 emissions. As noted above, clean fuels lead to large reductions in SO2 emissions. Similar large reductions in SAM can be expected as well. Therefore, low sulfur coal must be used to establish a BACT for SAM. Furthermore, as noted above, IGCC technology removes sulfur prior to combustion. This reduces SAM emissions. The BACT limit for SAM emissions from the proposed Elm Road Generating Station IGCC plant is 0.0005 lb/MMBtu. See Ex. 31 § II.11. This is $1/10^{th}$ of the limit for the CFB proposed for Unit 4. Therefore, for the same reasons that IGCC technology must be selected as the basis of BACT for SO2, it must also be used to establish BACT for SAM.

**Division's Response:**

*The Division does not concur with the conclusions of this comment. Sulfuric acid mist emissions are a function of the sulfur content of the fuel, and comparison of the Unit 4 emmisions to those of a unit which is burning lower sulfur coal is not appropriate. Installation of a WESP was eliminated in the*

*EKPC application on consideration of costs.*

**I. Mercury and Beryllium BACT Limits for Unit 4.**

The Permit for Spurlock 4 must contain a BACT limit for mercury and beryllium pursuant to 401 KAR 51:017. It should be noted that the existing Kentucky SIP requires BACT limits for facilities that emit mercury in a "significant" amount. The level at which mercury and beryllium emissions are emitted in a "significant" amount has recently been changed in the Kentucky administrative regulations, but the change has not yet been approved by the EPA. EPA proposed to adopt Kentucky's SIP revisions, 71 Fed. Reg. 6988, but has not issued a final rule to this effect. In fact, the comment period for the proposed change just closed. Unless and until the EPA approves the revisions to Kentucky's PSD program into Kentucky's SIP, the Division cannot issue PSD permits that conflict with the existing SIP. General Motors Corp. v. United States, 496 U.S. 530, 540 (1990) ("There can be little or no doubt that the existing SIP remains the "applicable implementation plan" even after the State has submitted a proposed revision."); United States v. Murphy Oil USA, Inc., 143 F.Supp.2d 1054, 1101 (W.D. Wis. 2001) (SIP cannot be changed without EPA approval).

Moreover, the new rules also require a BACT limit for mercury. Because mercury is "subject to [a] standard promulgated under 4[2] U.S.C. 7411," it is a "regulated NSR pollutant" under 401 KAR 51:001, sec. 1(210). See Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule, 70 Fed. Reg. 28606 (May 18, 2005) (to be codified at 40 C.F.R. pt. 60) (establishing limits for mercury pursuant to 42 U.S.C. § 7411). As a "regulated NSR pollutant" a BACT limit is required by 401 KAR 51:017, sec. 8. See also 401 KAR 51:001. sec. 1(221)(b) (because mercury is not listed in 401 KAR 51:001, sec. 1(221)(a), any amount of mercury emission is a "significant" amount.).

**1. Mercury BACT**

The Draft Permit establishes an emission limit for Mercury of 21 x 10-6 lb/MWh (Gross), based on a 12 month rolling average when burning coal. This is not BACT. The NEVCO Sevier permit established a mercury limit of 4x10-7 lb/MWh. Exs. 15, 16. This is assumed to be BACT for a CFB unit. NSR Manual at B.24 ("[I]t is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates" facts that show otherwise."). The Northeast States for Coordinated Air Use Management, in a comprehensive review of the available data, concluded that 90% mercury control is feasible and cost-effective. See Ex. 32. Vendors will guarantee 90% mercury control using bromiated carbon. Additional control is achievable with the use wet scrubbers and the addition of a heavy metal precipitation agent, trimercapto-s-triazine, tri-sodium salt ("TMT"), in the scrubber to convert mercury and other heavy metals to almost insoluble salts. The stable TMT-metal salts are separated from the flue gas and wet scrubbing liquor. The TMT is added to the scrubber slurry to meet a limit of 0.05 ppm mercury in the scrubber wastewater. This chemical prevents the re-emission of mercury from the scrubber and allows physical separation of mercury from the wastewater. J. Tarabocchia and R. Peldszus, Mercury Separation from Flue Gas and Scrub Water with Trimercapto-s-triazine (TMT). TMT is currently being used in Germany on

30,000-MW of coal-fired generation. The cost of using this additive is negligible in terms of cost per pound of mercury removed.

Packed beds of sorbent material is another control option that must be considered in a top-down BACT analysis. These devices have been used for over a decade to remove mercury, dioxins, and other HAPs from a wide range of combustion sources in both Europe and Japan. Donau Chemie offers Kombisorbon™, which uses a fixed-bed absorber packed with a mixture of activated carbon and an inert material. See Donau Carbon, KombisorbonTM – Process Description. This process is currently used on over 200 incinerators and other combustion sources in Europe and four incinerators in the United States. The vendor indicates that the process is commercially available for use on coal-fired units.

Another control technology that must be considered is similar to the Kombisorbon process. The MET-Mitsui-BG low temperature process, uses a packed bed of activated coke to simultaneously achieve 90% Hg removal, 80% NOx removal, and 99% SO2 and SO3 removal. The system can be designed to produce salable products including elemental sulfur, sulfuric acid, liquid SO2 or liquid mercury. E-mail from Marsulex Re: Can Activated Coke Be Used for Range of Pollutants, July 30, 2002. The process is installed on eight combustion systems in Japan and Germany, including four coal-fired boilers. D.G. Olson, K. Tsuji and C. Ward, The Reduction of Gas Phase Air Toxics from Combustion and Incineration Sources Using the GE-Mitsui-BF Activated Coke Process, 1999 International Ash Utilization Symposium, October 18-19, 1999.

A BACT determination for mercury must also consider the use of lower mercury coal, coal cleaning, and alternative combustion methods, such as IGCC. A lower mercury content in the fuel and a different coal combustion technique can dramatically reduce mercury emissions beyond the controls proposed for Spurlock 4, and, if used in combination with the controls described above, can achieve even greater mercury reductions. Additionally, EPA notes that "[a]n existing IGCC unit has demonstrated a process, using sulfur-impregnated AC carbon beds, which has proven to yield 90 to 95 percent Hg removal from the coal syngas." 69 Fed. Reg. at 4676. This corresponds to a similar finding presented by ChevronTexaco, that an IGCC facility could achieve greater than 90% mercury control by a method that is less expensive and more reliable than removal processes available for pulverized coal units. The Elm Road Generating Station permit for the proposed IGCC unit there establishes a BACT limit for mercury of 0.56 lb/trillion Btu. Ex. 31 § II.8. The BACT limit for Spurlock 4 must be at least this low, unless EKPC can justify rejection of IGCC

Additionally, coal cleaning can remove mercury prior to combustion. A study by the Commonwealth of Massachusetts indicates that advanced and commercially available coal cleaning technologies, such as Microcel and Ken-Flote, can remove 40 to 82 percent of mercury. Commonwealth of Massachusetts, Evaluation of Technological and Economic Feasibility of Controlling and Eliminating Mercury Emissions From the Combustion of Solid Fossil Fuel, at 19 (December 2002). The permit record for the Draft Permit demonstrates that coal cleaning was not considered as a basis for mercury BACT, despite the fact that the Division told EKPC over a year ago that "[c]oal washing is a proven technology to reduce[] SO2 and emissions of mercury and other Hazardous Air Pollutants." Letter from Markin to Huges, supra, p. 3 (Feb. 9, 2005). Nevertheless, it appears that EKPC failed to consider this (or any) option to achieve lower mercury emissions.

Additionally, the Draft Permit establishes an alternate mercury limit when burning tire derived fuel. Draft Permit § B.2., page 26. The Draft Permit states that when tire derived fuel is burned, EKPC must comply with a mercury limit established in 40 C.F.R. § 60.45a. Id. This is not BACT. The limit in 40 C.F.R. § 60.45a is a New Source Performance Standard, not a BACT limit. The Permit must contain a limit for mercury based on BACT for periods when TDF is co-fired with coal. 401 KAR 51:017, sec. 8.

2. **Beryllium BACT for Unit 4.**

The Draft Permit contains no limit for beryllium emissions from Unit 4. As noted above, the permit must contain a beryllium BACT limit because the Kentucky SIP, as currently approved by EPA, requires such a limit. This limit should be no greater than 0.0000146 lb/MMBtu, which is required from Spurlock Unit 3. See Draft Permit § B.2.j, page 12; (CITE- assumed to be BACT at other unit). However, the final PSD permit for the Weston 4 facility in Wisconsin sets a BACT limit for Beryllium of 1.3 lbs. per trillion Btu. This is assumed to be BACT for Spurlock 4.

**Division's Response:**

*No Prevention of Significant Deterioration ("PSD") analysis is required for mercury or beryllium. Section 112 of the Clean Air Act ("CAA"), 42 U.S.C. 7412, sets forth the requirements for hazardous air pollutants. CAA section 112(b)(6) specifies that "[t]he provisions of part C (prevention of significant deterioration) shall not apply to pollutants listed under this section." Mercury and beryllium compounds are listed in Section 112(b)(1) of the CAA. The CAA provides a note to Section 112(b)(1) explaining that "for all listings above which contain the word 'compounds'…the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical…as part of that chemical's infrastructure." Both mercury and beryllium are listed as HAPs , thus, neither are subject to PSD under the CAA.*

**J. There is No BACT Analysis for Tires.**

EKPC plans to burn tires in Unit 4. There is no analysis that Sierra Club could find in the record for BACT assuming co-firing tires with coal. All of the BACT analysis appears to assume 100% coal fuel. The Permit must limit fuel to the types analyzed in the top-down BACT analysis. Moreover, if burning tires leads to increased emissions, compared to burning 100% coal, a top-down BACT would prohibit co-firing tires because 100% coal would be a higher-ranked control option. Conversely, if burning tires results in lower emissions, compared to firing 100% coal, the permit should require EKPC to burn tires as a clean fuel (i.e., blending) option to reduce emissions. The permit record is simply too sparse regarding co-firing tires. The Division must reassess BACT if Unit 4 will burn tires.

**Division's Response:**

*Coal is the worst-case fuel that will be burned in this unit. Therefore, the BACT analysis for coal remains valid when a limited quantity of TDF is burned. The permit has been changed to include a specific limit on the percent (10% by fuel weight) of TDF which EKP is allowed to burn in Unit 4.*

**K. Startup, Shutdown and Malfunction Exemption**

The Draft Permit exempts Unit 4 from permit limits for PM, NOx and SO2 during periods of startup, shutdown and malfunction. Draft Permit p. 26. It is not clear if the exemption applies to all permit limits applicable to Unit 4, or only the NSPS limits—in which case the BACT limits would still apply during startup, shutdown, and malfunction. First, there is no definition of startup, shutdown or malfunction. Given the fact that the Draft Permit purports to waive the permit requirements for these periods, it is vital to an enforceable permit that these terms be narrowly and precisely defined. Second, the exemption fails to comply with the requirements of the Clean Air Act. BACT applies at all times, including startup, shutdown and malfunction. In re Tallmadge Energy Center, PSD Appeal No. 02-12 at p. 24 (EAB May 21, 2003); In re RockGen Energy Center, 8 E.A.D. 536, 553-55 (EAB 1999); In re Indeck-Miles Energy Center, PSD Appeal No. 04-01 (EAB Sept. 30, 2004). While the Draft Permit suggests that EKPC must "utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of [startup, shutdown, and malfunction] events," there is no indication that the Division undertook a BACT analysis to reach its apparent conclusion that BACT is good work practices alone. Draft Permit p. 26. The only suggestion that good work practices constitute BACT is the Division's assertion in its Statement of Basis. See Statement of Basis p. 25. Mere assertions are insufficient. RockGen Energy Center, 8 E.A.D. at 553-54. A top-down analysis must be conducted and documented in the record. The EAB in RockGen Energy Center held that if the permitting agency intends to exempt startup and shutdown periods from the BACT limit:

> it must make an on-the-record determination as to whether compliance with existing permit limitations is infeasible during startup and shutdown, and, if so, what design, control, methodological or other changes are appropriate for inclusion in the permit to minimize the excess emissions during these periods… If WDNR determines that compliance with the permit cannot be achieved during startup and shutdown despite best effort, it should specify and carefully circumscribe in the permit the conditions under which RockGen would be permitted to exceed otherwise applicable emission limits and establish that such conditions are nonetheless in compliance with applicable requirements, including NAAQS and increment provisions. Under such circumstances, a secondary PSD limit may also be considered, provided it is made part of the PSD permit and justified as BACT.

RockGen Energy Center, 8 E.A.D. at 554. This sets forth three requirements for a different limit applicable to startup and shutdown periods: 1) an on-the-record determination that compliance with the permit limits is infeasible during startup/shutdown; 2) if compliance is not feasible, specific requirements to minimize excess emissions during startup/shutdown based on a top-down BACT analysis; and 3) a determination that maximum emissions permitted during startup and shutdown do not exceed NAAQS or increment. None of these conditions are met, based on the record in this permitting action, for the startup/shutdown/malfunction exemption for Spurlock 4. Nor does the EPA allow excess emissions during malfunctions, even based on the very limited circumstances for startup and shutdown.

Moreover, good work practices does not constitute BACT for PM, NOx and SO2 emissions during startup, shutdown, and malfunction. Some SO2 control is achievable during each of these periods. Moreover, because natural gas or fuel oil will be fired during startup and shutdown periods, PM, NOx and SO2 emission rates will likely be low during these periods.

Additionally, NAAQS and increment applies all of the time, including periods of startup, shutdown and malfunction. Because no emission limit applies during these periods, how can the Division calculate emissions for modeling? How can the permit ensure compliance with NAAQS and increment when no emission limit applies during periods of startup, shutdown, and malfunction?

**Division's Response:**

*This is a base load-generating unit designed to operate at a high capacity factor, therefore startup and shutdown events will be kept to an absolute minimum for this unit. However, the Division concurs that monitoring and recordkeeping requirements relating to startups and shutdowns should be explicitly stated in the permit, as well as information needed to determine what are reasonable lengths of times for startups. This will be used to assure that the requirements of the permit and 401 KAR 50:055 are complied with during periods of startup and shutdown. Pursuant to 401 KAR 50:055, emissions must be minimized in a manner consistent with good air pollution control practices at all times.*

**V. BACT Limits for Coal/Material Handling.**

Coal handling operations that are added or increase operation with the addition of Unit 4 are subject to BACT. The Draft Permit does not contain BACT limits for coal handling (Emission Units 04 and 07). The Permit also does not include BACT limits for fly ash handling (Unit 06). If these operations will increase due to the addition of Unit 4, they must be subject to BACT.

Additionally, the Draft Permit establishes operating practices as BACT for coal storage piles (Emission Units 09). This does not represent BACT. BACT is emissions of no greater than 0.005 grains/dry standard cubic foot and no visible emissions, based on the permit for Indeck-Elwood in Illinois. See Ex. 33 p. 27. Furthermore, the Draft Permit states that a baghouse with 99% control efficiency is BACT. Draft Permit p. 41. Baghouses typically achieve 99.9% control. Therefore, the Draft Permit does not establish BACT limits for coal handling. Moreover, Sierra Club could not identify an actual top-down BACT analysis for the coal or material handling operations.

**Division's Response:**

*Based on the application as supplemented by additional information including the submittal on January, emissions from Units 04, 06, and 07 will not increase. Regarding emission unit 9, a limit in any other permit for any other facility (in this case, Indeck-Elwood) does not establish BACT at the Spurlock facility. While baghouses do regularly exceed 99% removal efficiency, it is not* *reasonable to establish anything higher as an enforceable limit on a facility which has not yet been built. The permit contains conditions which require the baghouse to be maintained and operated properly. You cannot 'detune' a baghouse to reach a removal efficiency less than the optimal for that installation, nor is there economic or other incentive to do so.*

## VI. CAM Plan Enforceability

The Title 5 permit for Spurlock must include an enforceable CAM plan, including enforceable indictor parameters, for a number of pollutants. A CAM plan is required by 40 C.F.R. pt. 64 for PM emission from Unit 1, NOx (CEMS), PM, and SO2 (CEMS) from Unit 2, PM, SO2 (CEMS) and NOx from Unit 3, and PM/PM10, SO2, NOx, and H2SO4 from Unit 4. SO2 and NOx will be measured by CEMS, which will also serve as the CAM requirement for those pollutants.

For each PM/PM10 limit for each unit, the permit requires the following:

- A schedule to be submitted within 6 months of permit issuance, which requires stack testing within a year of permit issuance "to establish the correlation between opacity and particulate emissions." Draft Permit § B.3.a., page 2;

- A stack test two years later (within the third year after permit issuance) "to demonstrate compliance with the allowable standard," but not to re-establish the correlation between opacity and particulate emissions. Draft Permit § B.3.b., page 2.

- Installation of COMS to measure opacity, including installing, calibrating, operating and maintaining the COMS. Draft Permit § B.4.a., page 3.

- A requirement that "Excluding the startup, shutdown, and once per hour exemption periods, if any six-minute average opacity value exceeds the opacity standard, the permit shall, as appropriate: 1) Accept the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs or; 2) Determine opacity using reference Method 9 if emissions are visible, inspect the COM and/or the control equipment, and make any necessary repairs. If a Method 9 [test] cannot be performed, the reason for not performing the test shall be documented." Draft Permit § B.4.a, page 3.

- A requirement that "opacity shall be used as an indicator of particulate matter emissions in conjunction with monitoring of the electrostatic precipitator's transformer/rectifier voltage and current levels." Draft Permit § B.4.b., page 3.

- A statement that "The opacity indicator level shall be established at a level that provides reasonable assurance that particulate matter emissions are in compliance when opacity is equal to or less than the indicator level." Draft Permit § B.4.b., page 3.

- A requirement that "If any six-minute average opacity (averaged over a period of three hours) value exceeds the opacity indicator level, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the

COM system and make any necessary repairs." Draft Permit § B.4.b.1., page 3.

- A requirement that "If five (5) percent or greater of COM data (data averaged over six-minute periods) recorded in a calendar quarter show excursions above the opacity indicator level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate matter standard while operating at representative conditions." However, the permit provides that "the Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected…" Draft Permit § B.4.b.2., p. 3.

- A requirement that "If primary or secondary voltage or current levels of the transformer/rectifier sets are found to be outside normal ranges, corrective action shall be initiated." Draft Permit § B.4.b.3., page 3.

This does not satisfy the requirements of 40 C.F.R. pt. 64. A source must design a monitoring system to gather data from one or more indicators of emission control performance that demonstrates that the source is complying with its applicable limits on an ongoing basis over the entire range of operating conditions for the source. 40 C.F.R. § 64.3(a)(1), (2). These indicators must be established as required monitoring in the permit, 40 C.F.R. § 64.6(c), including "[t]he means by which the owner or operator will define an exceedance or excursion for purposes of responding to and reporting exceedances or excursions under § 64.7 and 64.8 of this part." 40 C.F.R. § 64.6(c)(2). Moreover, the Title V permit for Spurlock must "specify the level at which an excursion or exceedance will be deemed to occur, including the appropriate averaging period associated with such exceedance or excursion." <u>Id.</u>

Title V of the Clean Air Act further requires that specific parameters be established in the permit as enforceable limits. <u>See</u> U.S. EPA , <u>Objection, Proposed Part 70 Operating Permit, Tampa Electric Co., F.J. Gannon Station, Permit No. 0570040-002-AV</u>.
While the permit does include parametric monitoring of emission unit and control equipment operations in the O&M plans for these units… the parametric monitoring scheme that has been specified is not adequate. The parameters to be monitored and the frequency of monitoring have been specified in the permit, but the parameters have not been set as enforceable limits. IN order to make the parametric monitoring conditions enforceable, a correlation needs to be developed between the control equipment parameter(s) to be monitored and the pollutant emission levels… In addition, an acceptable performance range for each parameter that is to be monitored should be established. The range, or the procedure used to establish the parametric ranges… should be specified in the permit. <u>Id.</u>

The permit must establish a correlation between the parameters and emission rates. <u>Id.</u> The permit must establish the parameters as enforceable permit limits. <u>Id.</u>; 40 C.F.R. § 70.6(a)(3). The permit must also require the source to maintain the monitoring equipment at all times, and conduct all required monitoring and recordkeeping, and to maintain the necessary parts for routine repairs. 40 C.F.R. §§ 64.7(b), (c), 70.6(a)(4). The permit must also require the source to report "the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken," and any monitoring downtime. 40 C.F.R. § 64.9(a). This reporting must be done as part of the 6-month reporting (and prompt reporting of violations), required by Part 70. 40 C.F.R. §§ 64.9(a), 70.6(a)(3)(iii). Additionally, the Reporting requirements for each unit must be amended to add a requirement that the source report excess emissions that exceed the indicator values established under the CAM plan.

Furthermore, the Draft Permit requires that pollution control equipment must be operated in accordance with manufacturer specifications or standard operating procedures. Draft Permit, p. 32 § 7(a). However, the Draft Permit fails to identify what these procedures are, or require that they be submitted to the Division and be subject to public review. This violates the requirement that the permit be enforceable as a practical matter, and that it be subject to public review and comment. Moreover, if the Division has not reviewed these specifications and standard operating procedures as part of the permitting record, the Division cannot rely on them and assume that they are sufficient to ensure compliance.

**Division's Response:**

*The Division acknowledges the comment but does not concur. The intent of Compliance Assurance Monitoring is not to establish new enforceable emission limitations, but rather requires monitoring to "provide a reasonable assurance of compliance with emission limitations or standards for the anticipated operations at a pollutant-specific emissions unit." In fact, one of the three-prong applicability requirements is that the unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof). 40 CFR 64.2(1) The other two requirements are that the unit uses a control device to achieve compliance with any such limitation or standard and that the unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than that quantity required to classify the unit as a major source.*

*If continuous emission monitoring systems (CEMS) or continuous opacity monitoring systems (COMS) are required, CAM requires that such systems be used to satisfy the CAM rules. 40 CFR 64.3(d). In the absence of continuous monitoring, CAM requires that indicators be established that provide an indication of whether or not a control device is working properly. As PM CEMS are not yet installed at existing units, opacity is commonly chosen as an indicator of PM compliance, as are electrostatic precipitator transformer/rectifier set voltages and currents. These electrical parameters provide an indication of whether the ESP is working properly. However, the specific voltage and current levels that indicate proper performance will vary from unit-to-unit, so CAM requires testing to establish a correlation between these levels and the impact they have on emissions. This interpretation is supported by the preamble to the CAM rulemaking, which states in part:*

> *"One method is to establish monitoring as a method for directly determining continuous compliance with applicable requirements. The Agency has adopted this approach in some rulemakings and, as discussed below, is committed to following this approach whenever appropriate in future rulemakings. Another approach is to establish monitoring for the purpose of: (1) Documenting continued operation of the control measures within ranges of specified indicators of performance (such as emissions, control device parameters and process parameters) that are designed to provide a reasonable assurance of compliance with applicable requirements; (2) indicating any excursions from these ranges; and (3)*

*responding to the data so that excursions are corrected."*

*The permit as drafted contains all applicable CAM requirements. With respect to the establishment of indicator levels and operating conditions, see, for example, Section B3, Testing Requirements (for Unit 1) on page 2 of the draft permit, which states in part: "This testing shall be conducted in accordance with 401 KAR 50:045, Performance Tests, and pursuant to 40 CFR 64.4(c)(1), the testing shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific source." With respect to monitoring, recordkeeping, and reporting see for example Section B.5(b)(3) and Section B.6(iii) on page 4 and 5 respectively of the draft permit.*

## VII. The Permit Record Contains Insufficient Monitoring and Modeling.

Every PSD permit must ensure that the source will not cause or contribute to a violation of a National Ambient Air Quality Standard or the maximum allowable increase over baseline air quality ("increment"). 401 KAR 51:017, secs. 2, 3. The PDS permit proposed for Spurlock Unit 4 fails to do so for a number for reasons.

### 1. The Draft Permit Does Not Establish Sufficient Emission Limits To Ensure Compliance.

PM limits for Units 1 and 2 are measured by Method 5, and are therefore filterable only. See 401 KAR 61:015, sec. 7. Therefore, these limits only apply to filterable PM. The total PM emissions, for purposes of modeling, must include emissions greater than 0.14 lb/MMBtu from Unit 1 and 0.1 lb/MMBtu from Unit 2 to include condensable fraction PM that contributes to ambient air quality and increment consumption.

Additionally, as noted above, the Draft Permit fails to contain an hourly mass emission limit for PM/PM10 emissions from the cooling tower and exempts periods of startup, shutdown and malfunction from the applicable BACT limits. Without limits on the hourly emissions, the Division cannot accurately model the impacts on ambient air quality and increment.

**Division's Response:**

*Modeling submitted by EKP was reviewed by the Division and found to have been based on the correct emission limits as contained in the draft permit. Since none of these limits are being relaxed in the proposed permit, then no additional impact over what was already modeled as acceptable is possible.*

### 2. The Source Has Not Analyzed Impacts To Nearby Nonattainment Areas.

The Spurlock plant is located close to the Cincinnati 8-hour ozone and PM2.5 nonattainment areas, as well as an additional PM2.5 nonattainment area in Ohio. There is no analysis that Sierra Club could find in the record regarding impacts of the facility on these areas. Additionally, to the extent that the emissions from Spurlock will contribute to violations of a NAAQS or increment, these exceedances cannot be excused based on the assertion that the impact from Spurlock's emissions is not "significant." The Clean Air Act does not provide an exception for sources that cause or contribute to nonattainment in less than a "significant" amount. Instead, the Act provides a bright line rule that applies to all sources that cause or contribute to a violation of NAAQS or increment—including those whose contribution is not "significant":

No major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless… the owner or operator of such facility demonstrates… that emissions from the construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region…

42 U.S.C. § 7475(a)(3). Because the Act does not allow a permit for any source that will cause or contribute to a violation of increment or NAAQS, in any amount, the permit must be denied if Spurlock 4 causes or contributes at all to such conditions.

**Division's Response:**

*DAQ and U.S. EPA do not presently require permittees to submit ozone modeling analysis for individual facilities, and no such analysis was required of EKPC. From studies associated with photochemical modeling and prior permitting actions, the Cabinet's experience shows that if $NO_x$ and VOC emissions are below the level at which a source would be required to do preconstruction monitoring analysis, then there will be no measurable effect on the airshed ozone levels, because those emissions would be below the sensitivity level of the models. With regard to particulate emissions, EPA requested that EKP provided a qualitative or quantitative assessment of whether emissions from Spurlock Unit 4 are likely to interfere with attainment of the fine particulate matter ($PM_{2.5}$) ambient standards in the greater Cincinnati $PM_{2.5}$ nonattainment area or in a separate $PM_{2.5}$ nonattainment area in Ohio.[3] (See EPA's request in their March 15, 2006 Comments (at 7).) Because EPA has not yet promulgated $PM_{2.5}$ implementation rules officially establishing the pollutants affecting $PM_{2.5}$ ambient air quality concentrations, EPA has recommended (in interim guidance dated April 5, 2005) that direct $PM_{10}$ emissions be used as a surrogate to address the NSR requirements for the $PM_{2.5}$ ambient standards. In response to the EPA comment, and using the approach suggested by EPA guidance, EKP reviewed its previous Unit 4 modeling results for $PM_{10}$ and assessed whether concentrations attributable to Unit 4 would exceed the $PM_{10}$ significant impact levels at the nearest $PM_{2.5}$ nonattainment areas. All modeling and analyses were conducted within the guidelines accepted by US EPA, including the elimination of impacts deemed not to be 'significant'.*

### 3. The Source Has Not Conducted Pre-Construction Ambient Air Quality Monitoring.

Although EPA guidance suggests that, in limited circumstances, an applicant

[3] EKP VOC emissions (Unit 4 and Unit 3 combined) are less than 100 tons per year. Therefore, an ambient impact analysis is not required for ozone per 401 KAR 51:017, Section 7(5). Additionally, emissions from Unit 4 are not significant as they are less than 40 tons per year at 24.53 tons per year.

such as EKPC can use existing air monitor data, rather than collecting data and submitting it with a PSD application, the Clean Air Act does allow anything other than site-specific monitoring. Section 165(e)(1), 42 U.S.C. § 7475(e)(1), states that "The review provided for in [42 U.S.C. § 7475(a)] shall be preceded by an analysis in accordance with regulations of the Administrator… which may be conducted by the State… or by the major emitting facility applying for such permit, of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant…" (emphasis added). Section 165(e)(2) clarifies that the analysis "shall include continuous air quality monitoring data gathered for purposes of determining whether emissions from such facility will exceed the maximum allowable increases or the maximum allowable concentration permitted under this part." 42 U.S.C. § 7475(e)(2). Therefore, the plain language of the Act requires: 1) an analysis according to EPA regulations; 2) to include ambient air quality information for the proposed site; and 3) which was collected for the purpose of determining NAAQS and increment consumption. Id.

Based on the language used by Congress, the Act appears to require site-specific monitoring for each permit application, and not to permit other data-- collected for other purposes-- be used. The Division and the applicant do not have the option to avoid mandatory language in the Act based on convenience. It is not clear from the record available to Sierra Club whether this monitoring was conducted and, if so, for how long.

**Division's Response:**

*EKPC conducted pre-construction ambient air quality monitoring for PM10 and SO2, the only two pollutants for which monitoring was required. The monitoring was conducted from April 2002-December 2003 in Mason County and in Ohio.*

**4. The Baseline Cannot Include Emissions from Unit 2, and Unit 2 Emissions Consume Increment.**

Emissions from the construction of major sources (including major modifications) after June 6, 1975 are not included in the baseline concentration of air pollution for determining increment consumption. 401 KAR 51:011, sec. 1(22)(b)1. As noted above, Unit 2 was modified after June 6, 1975 without obtaining the required PSD permits. Therefore, the emissions which result from the modification are not included in the baseline concentration and, instead, consume increment.

**Division's Response:**

*In the application, Unit 2 is recognized as an increment consuming source and was treated as such in the modeled ambient air impact analysis.*

**5. For Modeled Exceedances For Which Spurlock 4 Will Not Be A Significant Source, The Division Must Reopen the Permits for the Contributing Sources.**

As noted above, if Spurlock will cause or contribute to a violation of NAAQS or increment, the permit must be denied. To the extent that the Division determines that Spurlock does not cause or contribute to modeled violations, the Division must nevertheless “take remedial action through the applicable provisions of the state implementation plan to address the predicted violations(s).” NSR Manual at B.52. Therefore, the Division must reopen permits or revise the SIP to prevent the modeled violations, even if Spurlock is not the cause.

**Division’s Response:**

*The Division acknowledges this comment but, since Spurlock was determined not to cause or contribute to modeled violations, this comment has no bearing on this permit.*

**6. The Permit Cannot Be Issued Because Unit 4 Will Cause or Contribute to NAAQS Nonattainmnent.**

EKPC’s PSD permit application includes modeling showing that the HSGF emissions contribute to and exacerbate violations of the 3-hour and 24-hour national ambient air quality standards (NAAQS) for $SO_2$. These NAAQS violations take place about 28 miles northwest of the Spurlock project site, occurring in simple terrain (terrain elevations less than the height of the boiler stack top). The permit application modeling analysis reveals a highest second high 3-hour $SO_2$ air concentration of 1642.6 µg/m$^3$. This modeled value exceeds the 3-hour NAAQS of 1300 µg/m$^3$ by over 26 percent. The Spurlock Unit 4 modeling also shows a highest second high 24-hour $SO_2$ air concentration of 465.5 µg/m$^3$, which is significantly greater than the 24-hour NAAQS of 365 µg/m$^3$.

These modeled impacts are almost certainly underestimates, due to the absence of site-specific meteorological data that includes hourly measurements of low wind speed conditions (see comment below). The modeled $SO_2$ NAAQS violations are summarized in the following table:

NAAQS Analysis Using Applicant’s $SO_2$ Emission Rates

NAAQS Analysis Using Applicant’s $SO_2$ Emission Rates

| Year of Meteorological Data | 2nd High 3-hr $SO_2$ Concentration (µg/m$^3$) | 2nd High 24-hr $SO_2$ Concentration (µg/m$^3$) | Easting Coordinate (meters) | Northing Coordinate (meters) |
|---|---|---|---|---|
| 1990 | 1496.6 [4] | | 222200.0 | 4321000.0 |
| 1990 | | 372.0 [5] | 222400.0 | 4320700.0 |
| 1991 | **1642.6** [6] | | 221900.0 | 4322400.0 |
| 1991 | | 351.7 [7] | 221900.0 | 4322400.0 |

4 From Applicant’s ISCST3 input file: SO2-NAAQS-100mGrids-3hr-1990_90_SO2.LST

5 From Applicant’s ISCST3 input file: SO2-NAAQS-100mGrids-24hr-1990_90_SO2.LST

6 From Applicant’s ISCST3 input file: SO2-NAAQS-100mGrids-3hr-1991_91_SO2.LST

7 From Applicant’s ISCST3 input file: SO2-NAAQS-100mGrids-24hr-1991_91_SO2.LST

| | | | | |
|---|---|---|---|---|
| 1992 | 1549.5 8 | | 222500.0 | 4320400.0 |
| 1992 | | 391.5 9 | 221800.0 | 4322400.0 |
| 1993 | 1619.9 10 | | 222800.0 | 4321200.0 |
| 1993 | | **465.5** 11 | 222300.0 | 4321200.0 |
| 1994 | 1474.3 12 | | 222900.0 | 4315800.0 |
| 1994 | | 452.1 13 | 221800.0 | 4323500.0 |

**Division's Response:**

*The Division reviewed for accuracy the modeling analysis submitted by EKPC to determine whether the facility will cause any violations of the primary or secondary NAAQS. The modeling protocol was reviewed to determine if it had followed generally accepted modeling requirements and practices. Based on the analysis, the Division determined that the project, as permitted, will not cause or contribute to NAAQS non-attainment.*

**7. The Covington/Cincinnati Airport Meteorological Data are Unacceptable for Modeling Spurlock's Air Emissions**

EKPC's PSD Permit Application assesses compliance with the NAAQS and PSD increments using five years of meteorological data from Covington/Cincinnati Airport. The airport data, collected at a location about 60 miles from the Spurlock plant, is neither site-specific nor is the quality of the data acceptable for air dispersion modeling. The Spurlock Unit 4 permit application, which relies on these data for air modeling, is therefore flawed.

For air dispersion modeling purposes, airport data are among the least desirable. Problems with location and the general quality of data are the primary concerns. The USEPA, in their Meteorological Monitoring Guidance for Regulatory Modeling Applications, summarizes these concerns about using airport data:

For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however, one should be ware that airport data, in general do not meet this guidance.

USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 1-1. First and foremost, the Covington/Cincinnati airport data are not site-specific to the Spurlock facility. The

8 From Applicant's ISCST3 input file: SO2-NAAQS-100mGrids-3hr-1992_92_SO2.LST

9 From Applicant's ISCST3 input file: SO2-NAAQS-100mGrids-24hr-1992_92_SO2.LST

10 From Applicant's ISCST3 input file: SO2-NAAQS-100mGrids-3hr-1993_93_SO2.LST

11 From Applicant's ISCST3 input file: SO2-NAAQS-100mGrids-24hr-1993_93_SO2.LST

12 From Applicant's ISCST3 input file: SO2-NAAQS-100mGrids-3hr-1994_94_SO2.LST

13 From Applicant's ISCST3 input file: SO2-NAAQS-100mGrids-24hr-1994_94_SO2.LST

distance involved (about 60 miles) makes the airport data non site-specific, with numerous land use classifications existing between Spurlock and the airport. Most important, however, are the difference in land uses around the Spurlock plant and the airport. Covington/Cincinnati Airport is comprised of concrete runways, parking lots, passenger terminals, and other structures associated with air travel activities. These surface and building characteristics in turn affect the boundary layer meteorology present at the airport. Oke T.R., Boundary Layer Climates, Halsted Press, 1978, pp. 240-241. In addition, landings, takeoffs, and idling of airplanes affect the site-specific conditions at the airport such that the meteorological conditions are not representative of the area surrounding the Spurlock facility.

The other major issue is the quality of the meteorological data collected at Covington/Cincinnati Airport. It is important to remember that the airport data were not collected with the thought of air dispersion modeling in mind. For example, airport conditions are typically reported once per hour, based on a single observation (usually) taken in the last ten minutes of each hour. The USEPA recommends that sampling rates of 60 to 360 per hour, at a minimum, be used to calculate hourly-averaged meteorological data. USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 4-2. Air dispersion modeling requires hourly-averaged data, which represents the entire hour being modeled, and not only a snapshot taken in one moment during the hour.

Additionally, data collected at Covington/Cincinnati Airport are not subject to the system accuracies required for meteorological data collected for air dispersion modeling. The USEPA recommends that meteorological monitoring for dispersion modeling use equipment that are sensitive enough to measure all conditions necessary for verifying compliance with the NAAQS and PSD increments. For example, low wind speeds (down to 1.0 meter per second) are usually associated with peak air quality impacts – this is because modeled impacts are inversely proportional to wind speed. Following USEPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second or less. Id., p. 5-2. And the wind speed measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second. Id., p. 5-1. However, the Covington/Cincinnati Airport data used by EKPC is based on wind speed observations that are reported in whole knots, rather than being measured in 0.1 meter per second increments. This is evidenced by examining the meteorological data files used in the permit application modeling analyses. Every modeled hourly wind speed is a factor of 0.51 or 0.52 meter per second (the units required for input to the air dispersion model), which exists because one knot equals 0.51479 meter per second. The once-per-hour observations at Covington/Cincinnati Airport (in whole knots, no fractions or decimals) were converted to meters per second and can therefore be back-converted to the whole knot measurements originally reported by the airport.

To further exemplify the problem of using the airport data, the lowest wind speed included in the meteorological data files used in the permit application modeling analyses is 1.54 meters per second. This equals three knots exactly, which is the lowest wind speed reported by the airport. In other words, any winds lower than three knots are reported as calms, and are thus excluded from the modeling analyses. This is significant because there are 2,381 such calm hours in the five years of meteorological data used in the permit application. The most critical conditions for verifying compliance with the NAAQS and PSD increments (low wind speeds) are being excluded from the HSGF analysis because of the choice to use distant airport data.

Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second (about one knot), which can then be used as 1.0 meter per second in the air dispersion modeling analyses. This will greatly increase the number of hours included in the modeling analyses and will include the very data points that are most important when verifying compliance with the NAAQS or PSD increments. Simply put, the meteorological data used in the Spurlock permit application includes no wind speeds below 1.54 meters per second, and to compound the problem, lists the lowest wind speed observations as "calm," which are then excluded from the model calculations. This is unjustified and prejudices the modeling by excluding the periods when modeled concentrations would be highest.

The Division must require EKPC to collect pre-construction meteorological data for use in their permit application modeling. Spurlock Unit 4, which is a major emission source of many air pollutants, should not be assessed for PSD increment and NAAQS compliance using distant meteorological data collected with none of the quality assurances necessary for air modeling data. USEPA, Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-07, May 1987, p. 55. EKPC must be required to collect pre-construction meteorological data for use in verifying compliance with all Spurlock air emissions before any operating permits are issued.

Pre-construction meteorological data for projects that trigger PSD review is already being required for coal-fired power plants. Two recent projects in Nevada, Granite Fox Power (near Gerlach) and Newmont Nevada (Boulder Valley), have collected at least one year of pre-construction meteorological data. The data requirements, specific for input to air dispersion modeling for NAAQS and PSD increment analyses, are specified by the State of Nevada. See Nevada Bureau of Air Pollution Control, Ambient Air Quality Monitoring Guidelines, May 4, 2000. The State of Nevada Guidelines state: "Current on-site meteorological data are required for input to dispersion models used for analyzing the potential impacts from the air pollution sources at the facility." Id., p. 6.

Many air regulatory agencies have been requiring pre-construction meteorological data for many years. As part of their PSD program, the Santa Barbara County (California) Air Pollution Control district requires at least one-year of pre-construction air quality and meteorological monitoring. Santa Barbara County Air Pollution Control District, Rule 803, Prevention of Significant Deterioration.[21] PSD sources in Santa Barbara County must collect site-specific hourly-averaged values for the following meteorological parameters:

- Horizontal wind speed and wind direction (both arithmetic and resultant)
- Horizontal wind direction standard deviation (sigma theta)
- Standard deviation of wind speed normal to resultant wind direction (sigma v)
- Vertical wind speed
- Vertical wind speed standard deviation (sigma w)
- Standard deviation of the vertical wind direction (sigma phi)

- Ambient air temperature
- Shelter temperature[22]

Spurlock will release a very large volume of air emissions into a very complex area impacted by point, area, and volume sources. The low quality, non site-specific meteorological data set used to model for the PSD permit is inadequate. The permit should be denied because of this poor modeling practice, and not be resumed until EKPC has collected at least one year of site-specific meteorological data consistent with USEPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications.

**Division's Response:**

*In doing the modeling submitted with the application, EKP followed the procedures under Appendix W to 40 CFR 51. While EPA has issued guidance that indicates that airport data is not the preferred data for modeling, there is no statutory or regulatory prohibition from using it when it has been determined, on a case-by-case basis, that it is acceptable. That question was considered in this case, and the Division concluded that use of airport data was acceptable.*

### VIII. The Public Notice Was Deficient.

Public notice of proposed Title V permits, under 401 KAR 52:020, must include a description of emission increase and the level of increment consumption. 401 KAR 52:100, sec. 5(9) and (10). The public notice that Sierra Club received (attached as Ex. 34) does not contain the required disclosures. Therefore, the Division must re-notice the permit, by providing an adequate public notice, and provide a new public comment period.

**Division's Response:**

*The Public notice advertising the public comment period containing the information regarding emission increases and increment consumption was published in the Ledger Independent, a newspaper located in Maysville, KY, on February 16, 2006.*

### IX. The Permit Must Ensure and Require Compliance with 401 KAR 50:055, Section 4.

The Draft Permit fails to require compliance with 401 KAR 50:055, Section 5, which provides that: "No person shall permit or cause air pollution as defined in 401 KAR 50:010 in violation of the regulations promulgated by the cabinet." While this requirement is related to other regulatory requirements, it is a separate requirement. The permit must contain a provision prohibiting the source from causing "air pollution."

**Division's Response:**

*Regulation 401 KAR 50:055 does not prohibit a source from causing "air pollution" as stated at the end of this comment, but rather from causing air pollution as defined in 401 KAR 50:010* ***in violation of the regulations promulgated by the cabinet*** *(emphasis added). Compliance with the permit will ensure compliance with 401 KAR 50:055.*

**X. All Reporting Must Be Certified By A Representative of the Source.**

Sierra Club notes that a number of reporting requirements in the Draft Permit violate the requirement that all "reports of required monitoring… must be certified by a responsible official consistent with [40 C.F.R.] § 70.5(d)…" 40 C.F.R. § 70.6(a)(3)(iii)(A). Section 70.5(d), in turn, provides that:
Any… report, or compliance certification submitted pursuant to these regulations shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under this part shall state that, based on information and belief formed after reasonable inquiry, the statements and information are true, accurate and complete.

40 C.F.R. § 70.5(d). Provisions of the Draft Permit provide that "Opacity data shall be reported in electronic files only." See e.g., Draft Permit p. 5. However, this does not require that the reports be certified by a responsible official. The electronic records that Sierra Club reviewed indicates that there is no signature by a responsible official on the opacity excess emission reports. This must be clarified in the Permit by requiring all reporting to be certified, including reports submitted in electronic format.

**Division's Response:**

*Section F. 6. of the permit states, in part: "All reports shall be certified by a responsible official pursuant to 401 KAR 52:020 Section 23." The permittee must comply with this provision to be in compliance with the permit. Since the report itself must be certified, the Division believes that it is unnecessary to require a separate certification on any data accompanying the report.*

**XI. Hazardous Air Pollutant Limits.**

The Draft Permit states that compliance with emission limits in subsections (a) (particulate matter), (d) $SO_2$; (f) CO; and (l) sulfuric acid mist, "shall constitute compliance with 401 KAR 63:020 with respect to toxic substances." Draft Permit, p. 26, condition (n). There is no discernable basis for this conclusion in the permit record. Moreover, there is nothing to indicate that the Cabinet complied with the requirement in 401 KAR 63:020, section 3, to evaluate the impacts of Spurlock's emissions" which may be "harmful to the health and welfare of humans, animals and plants" The record does not evaluate the individual, cumulative, and synergistic impacts of potentially hazardous matter and toxic substances, and set limits to assure no harm. Instead, the Draft Permit merely points to BACT emission limits on particulate matter, $SO_2$ and SAM as constituting compliance with 401 KAR 63:020. This is inadequate for a number of reasons. First, these BACT limits apply to only a small subset of the toxic substances that will be emitted by Unit 4. Second, BACT limits are technology based limits and are not set to protect the health and welfare of humans, animals, and plants. Finally, the Permit is silent as to limits for other potentially hazardous substances that would be emitted by Unit 4, including beryllium, lead, hexavalent chromium, PM2.5, dioxins, and polynuclear aromatic hydrocarbons, among many others.

**Division's Response:**

*401 KAR 63:020 requires that "no owner or operator shall allow any affected facility to emit potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants. Evaluation of such facilities as to adequacy of controls and/or procedures and emissions potential will be made on an individual basis by the cabinet." Regarding this permit, the Division for Air Quality ("DAQ") evaluated the Spurlock 4 unit on an individual basis by reviewing the adequacy of controls and/or procedures to be implemented with the potential emissions from the facility and evaluated those factors according to its collective technical experience, engineering knowledge and professional judgment to determine that the facility would not emit potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants. DAQ utilized its best professional judgment and discretion in determining whether additional measures were required under 401 KAR 63:020 to protect against adverse ecological effects from the emissions, and concludes that no additional limits are required..*

### XII. Miscellaneous Activities.

The list of "Insignificant Activities" on pages 67-69 of the Draft Permit include some activities that are not "insignificant." For example, stationary fire pumps, flue gas conditioning systems, emergency generators, lime handling system, fly ash storage silos, railcar/truck flyash loadout are all listed. None of these activities are insignificant. There should be specific permit limits for all of these activities. Moreover, there appears to be no permit conditions on haul roads, despite the fact that PM emissions from such sources are major contributors to potential NAAQS and increment violations.

**Division's Response:**

*Based on the emissions analyses contained in the application, all activities listed on the "Insignificant Activities" list are properly identified, and no further limits or permit conditions are required.*

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[1] The Division should request copies from EKPC of all missing records. Additionally, the compliance records that Sierra Club received were not signed by an authorized representative of EKPC, attesting to the truth and accuracy of the records. The Division should ensure that it has and that it requires signed and certified copies of all compliance records. 40 C.F.R. § 70.6(a)(3)(iii).

[2] The excess emission reports state that the limit for Unit 1 is 40% opacity. The Draft Permit, however, contains a 20% opacity emission limit for Unit 1. See Draft Permit p. 1. This discrepancy should be addressed. To the extent that EKPC's excess emission reports are inaccurate, the Division should request corrected reports.

[3] See Excess Emission Reports, Attached as Exhibit 1.

[4] The Permit indicates that the SO2 limit for Unit 1 is based on 401 KAR 61:015, section 1(3)(e). We are unable to locate 401 KAR 61:015, section 1(3)(e).

[5] See Excess Emission Reports, attached as Ex. 1.

[6] A visible emission standard is a limit on "light scattering particles," which include both fine particulate matter ("PM") and sulfuric acid mist ("SAM") aerosols. Both PM and SAM are regulated under PSD and, therefore, a complete PSD permit must contain a BACT limit which includes a visible emission limit based on BACT for PM and SAM.

[7] EKPC's application misrepresents this permit limit as 0.01 lb/MMBtu. See Permit Application p. 3-6 (Sept. 13, 2004).

[8] EKPC cherry picks when it refers to AES Puerto Rico. It relies on AES Puerto Rico to support a higher PM limit, but attempts to avoid the AES Puerto Rico lower SO2 limit. Compare EKPC Jan. 2006, p. 21 (AES SO2 limit "distinguishable") with Id., p. 24 (AES PM limit "appropriate for Unit 4.").

[9] Additionally, that the emission limits in the Draft Permit include a condition requiring that "reasonable precautions" be taken to prevent PM from becoming airborne. Draft Permit, p. 65. However, the Draft Permit does not define what reasonable precautions might be, making the condition ambiguous and thus not enforceable.

[10] This is a misleading statement, because EKPC also states that "East Kentucky Power wishes to have the capability to fire both high and low-sulfur coal in the proposed new CFB Boiler." Permit Application p. 3-8 (Sept. 13, 2004).

[11] Even if low sulfur coal were not cost effective, EKPC would have to consider blending low sulfur coal with the high-sulfur coal it proposes to burn as a method of reducing the average sulfur content of the fuel coal.

[12] It should be noted that EKPC's analysis also underestimates the SO2 removal for PRB coal, and therefore increases the cost-per-ton of SO2 removed. See EKPC Jan. 2006 Supp. p. 7 (assumes 98% control for all coals, except PRB coal). If the same 98% control were assumed for PRB coal (which is achievable with various wet scrubbers), the cost per ton of SO2 removed for PRB coal is $5,838/ton. This is very cost effective. Additionally, if the cost of SO2 credits is included, which currently cost between $1,800 and $2,500 per ton, low sulfur fuel is even more cost effective.

[13] Ironically, EKPC attempts to claim that Spurlock 4 is "designed" to burn only high sulfur fuel, and therefore, cannot burn lower sulfur fuels to reduce SO2, and also claims that it will burn low sulfur fuels and, therefore, cannot use an electrostatic precipitator to reduce PM/PM10 emissions. Compare Letter from Robert E. Hughes, Jr., EKPC, to Donald Newell, DAQ p. 9 (Nov. 9, 2005) (Spurlock 4 cannot burn low sulfur fuel) with Permit Application p. 3-8 (Sept. 13, 2004) (EKPC cannot achieve lower PM emission rates by using an ESP because it "wishes to have the capability to fire both high and low-sulfur coal…"). EKPC drops the reference to "low sulfur" fuels in its January, 2006 submittal, but nevertheless refers to it by implication. EKPC continues to maintain that it plans to use coal with "high resistivity fly ash," which refers to low sulfur, likely PRB coal. EKPC Jan. 2006 Submittal, p. 22. If the Division intends to allow EKPC to avoid the requirements of BACT by refusing to consider lower sulfur coal to reduce SO2, it must require EKPC to reevaluate its PM/PM10 limits by using a high-efficiency ESP. It must also make burning high sulfur coal a permit requirement, which would necessitate a new permit (i.e., constitute a major modification) if EKPC wishes to burn any lower sulfur coal in the future. See e.g., Hawaii Elec. Co., 723 F.2d at 1448.

[14] It should be noted that using lower sulfur coal achieves significantly lower SO2 emissions than coal washing, and has a lower incremental cost. EKPC Jan. 2006 Submittal. p. 8. Therefore, the analysis of coal washing, while required in a top-down BACT analysis, is academic because lower-sulfur coal is a higher-ranked and cost effective SO2 control option. Nevertheless, EKPC's incremental cost effectiveness assertions are baseless.

[15] This is inconsistent with page 38 of the January 2006 submittal, where EKPC assumes only 60% control from the dry scrubber.

[16] United States of America v. West Penn Power Company, Civil Action No. 77-1142 and Commonwealth of Pennsylvania, Department of Environmental Resources v. West Penn Power Company, No. 1309, C.D. 1979.

[17] For example, coal sulfur content can vary. Additionally, EKPC incorrectly assumes 100% of the sulfur in the fuel will convert to SO2. Typically, 10-15% of the sulfur will be removed in transport, crushing, or other processing. Additional sulfur is converted to SO3 and sulfuric acid. Therefore, a removal efficiency requirement for the FGD ensures that EKPC operates the FGD at maximum efficiency, regardless of the SO2 inlet rate.

[18] lb/MMBtu = (ppmv)(9780)(molecular weight)(E-6)/379.6

[19] The Warrior Run CFB averaged between 0.05 and 0.06 lb/MMBtu while the SNCR was operating, during the ozone season. This is below the applicable limit for Warrior Run, so the unit was likely not maximizing control. Therefore, while Warrior Run data does not demonstrate the maximum level of control, it does demonstrate that other units are already achieving NOx emissions lower than 0.07 lb/MMBt.

[20] EKPC submitted an early estimate of costs for an SCR, but that analysis was sufficiently flawed (erroneously assuming an SCR and SNCR combination, assuming over-control and the sale of NOx credits, etc) that EKPC submitted a revised analysis. These comments relate to the January 2006 submittal. Sierra Club assumes that EKPC's significantly revised January, 2006 figures acknowledge the fact that prior EKPC submittals are irrelevant.

[21] The meteorological monitoring requirements are specified in a detailed protocol that implements their PSD Rule. See Barbara County Air Pollution Control District, Air Quality and Meteorological Monitoring Protocol for Santa Barbara County, October 1990.

[22] Id., p. 57.